MONTANUNIVERSITÄT LEOBEN

Department Mineral Resources and Petroleum Engineering

Master thesis

Assessment of Measurement Methods used in Oil Production

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November, 2011

AFFIDAVIT

I declare in Lieu of oath, that I wrote this thesis and performed the associated research myself, using only literature cited in this master thesis.

AHLAM FARAG NABIL, November 2011

Dedication

I would like to dedicate this thesis to my parents. Farag and Suad, who have accompanied my education for a long time and never stop encourage me and support me. A special thanks to my sisters Afaf, Enas and Samla, and to my brothers Sami and Mohamed for everything.

Acknowledgements

Thank God all the time and forever.

I would like to express my gratitude to Dr. Wilhelm Brandstätter whose encouragement, invaluable supervision and guidance and overall direction of this thesis.

I would like to thank Professor Herbert Hofstätter for his support and advices.

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Abstract

The oil industry has substantially changed over the last 20 years in production mechanisms and in the instruments principles to measure various kinds of the petroleum fluid properties. These measurements have a great impact on reservoir management, well performance monitoring, production forecasting, development of the field, integrated process efficiency as well as on the economics. Additionally, measurements can be used to predict problems before they are encountered.

The goal of this thesis is to assess the state of the art of the experimental methods in the upstream oil industry. It also presents the measurement fluids properties along the journey from starting point till the final destination at the market of the petroleum industry. Also, highlighting the Obstacles that face some devices and influencing their reliability in the measuring accuracy.

What's more, it is shown a number of opportunities to improve the quality and the accuracy of the current measurements methodologies. Future trends also analyzed to gaining a better understanding of the petroleum fluids.

Kurzfassung

Die Ölindustrie hat sich in den 20 Jahren in der Produktion Mechanismen und in den Instrumenten Prinzipien geändert werden, um verschiedene Arten der Erdöl Flüssigkeit Eigenschaften zu messen. Diese Messungen haben einen großen Einfluss auf Reservoir-Management, sowie Performance-Überwachung, Produktion Prognose, Entwicklung des Feldes, integrierten Prozess-Effizienz sowie auf die Wirtschaftlichkeit. Darüber hinaus können die Messungen verwendet werden, um Probleme vorherzusagen, bevor sie auftreten werden.

Das Ziel dieser Diplomarbeit ist es, den Zustand der Kunst der experimentellen Methoden in der Upstream-Öl-Industrie zu beurteilen. Es zeigt auch die Messung Flüssigkeiten Eigenschaften entlang der Reise vom Ausgangspunkt bis zum Zielort auf dem Markt der Erdölindustrie. Auch Hervorhebung der Hindernisse, dass einige Geräte Gesicht und Einfluss auf ihre Zuverlässigkeit bei der Messgenauigkeit. Was mehr ist, ist es eine Reihe von Möglichkeiten, die Qualität und die Genauigkeit der Strommessung Methoden verbessert werden muss. Zukünftige Trends auch für ein besseres Verständnis der Erdöl-Flüssigkeiten analysiert.

Important definitions

- **Accuracy:** is defined as the qualitative expression for the closeness of a measurement to the true value.

Accuracy can be expressed in many ways including:

- In Engineering Units (i.e. ± 2°C).
- As a Percentage of Reading or of Actual Value (i.e. ± 0.5% of Reading).
- As a Percentage of Full-scale (i.e. ± 0.2% of FSD).
- As a Percentage of Span (the same as percentage of full-scale if the range is zero starting).
- Specified accuracy can change for different parts of the measuring range or can be expressed as a formula, for example A Pt100 resistance thermometer has an accuracy specified as ±(0.15 + 0.002T) °C where T is measured temperature (°C).
- **Span:** the algebric difference between the lower and upper range limits.
- **Repeatability**

Repeatability of a Measurement

The quantitative expression of the closeness of agreement between successive measurements of the same value or quantity carried out by the same method with the same measuring instrument at the same location over appropriately short intervals of time.

Repeatability of a Measuring Instrument

The quality, which characterises the ability of the measuring instrument to give identical indications or responses for repeated applications of the same value of the quantity measured under, stated conditions of use. An instrument that is repeatable is not necessarily accurate. Although not a desirable situation, this may not have serious repercussions if the instrument is solely used for control purposes. In the case of the volt meter above repeatability can be affected by variations in the wave shape. Environmental parameters also affect repeatability such as the ambient temperature or vibration at the instrument location. The variations in reading of an instrument deviate from the mean value in accordance with established statistical laws.

- **Rangeability (Turndown):** the Range-ability or Turn-down of an instrument is defined as the ratio of the maximum to the minimum specified measured values at which the instrument has an acceptable performance.
- **Royalty Transfer:** a specialized form of measurements. The basis for paying a fee or percentage of the revenues generated by the sales (royalty) to owners of private or state owned enterprises
- **Custody Transfer:** a measurement of transfer of a deliverable at the point of change of responsibility, providing quantity and quality information used for the physical and fiscal documentation of a change in ownership and/or responsibility of

commodities between two parties possessing a contractual agreement and bound by the terms and conditions of such a contract.

- **Calibration of an Instrument or Meter:** the process or procedure of adjusting an instrument or a meter so that its indication or registration is in close agreement with a referenced standard.
- **Critical Flow Prover:** a test nozzle that is used to test the throughput of a gas meter where the linear velocity in the throat reaches the sonic velocity of the gas.
- **Differential Pressure:** the drop in pressure across a head device at specifie pressure tap locations. It is normally measured in inches or millimeters of water.
- **Meter Proving:** the procedure required to determine the relationship between
  the .true. volume of fluid measured by prover and the volume indicated by the meter.
- **Orifice Plate:** a thin plate in which a circular concentric aperture (bore) has been machined. The orifice plate is described as a .thin plate. and .with sharp edge,. because the thickness of the plate material is small compared with the internal diameter of the measuring aperture (bore) and because the upstream edge of the measuring aperture is sharp and square.
- **Pressure, Reid Vapor (RVP):** the vapor pressure of a liquid at 100°F (37.78°C) as determined by ASTM D 323-58, Standard

Method of Test for Vapor Pressure of Petroleum Products (Reid Method).

- **Provers:** devices of known volume used to prove a meter.
- **Refined Products:** the products that have been processed from raw materials to remove impurities.
- **Tank Gauging:** a defined procedure of measurement of fluids in tanks by level determination.

Chapter 1

1. Petroleum field processing and measured properties-crude oil

1.1 Introduction

This chapter discusses the major processes loop for the crude oil production stage from the wellhead which is the starting point till the ultimate destination is either a sales in the market or sending to the refinary plant to prodcue other product.The complex nature of the wellstream is responsible for the complex processing of the produced fluids(gas, oil, water, and solid). The hydrocarbon portion must be seperated into products that can be stored and/or transported. The nonhydrocarbon contaminants must be removed as much as feasible to meet storage , transport, reinjection, and disposal specifications as shown in figure (1). Ultimate disposal of the varoius waste streams depend on factors such aas the location of the field and the applicable environmental regulations.Having the accurate measurement is very important for production engineer and reservoir engineer and for project parteners. These information can be used in simulation for properties estimation and for hidtory matching the early data gathered during the beginning of the field production life used for designs surface installations and later on for production optimization. Another practice of the data gathered is design of pipes sizesof the transportation routes. Some measurements can be useful to predict some problems and avoid the loss to fix the problem resulated of the problem.

1.2 Cycle of the produced oil management

The petroleum fluid – crude oil, gas – to be produced must be processed before sale, transport, and reinjection. Therefore, oil and gas production involve a number of surface unit operation between the well head and the point of custody transfer or transport from the production facilities figure (1).[1]

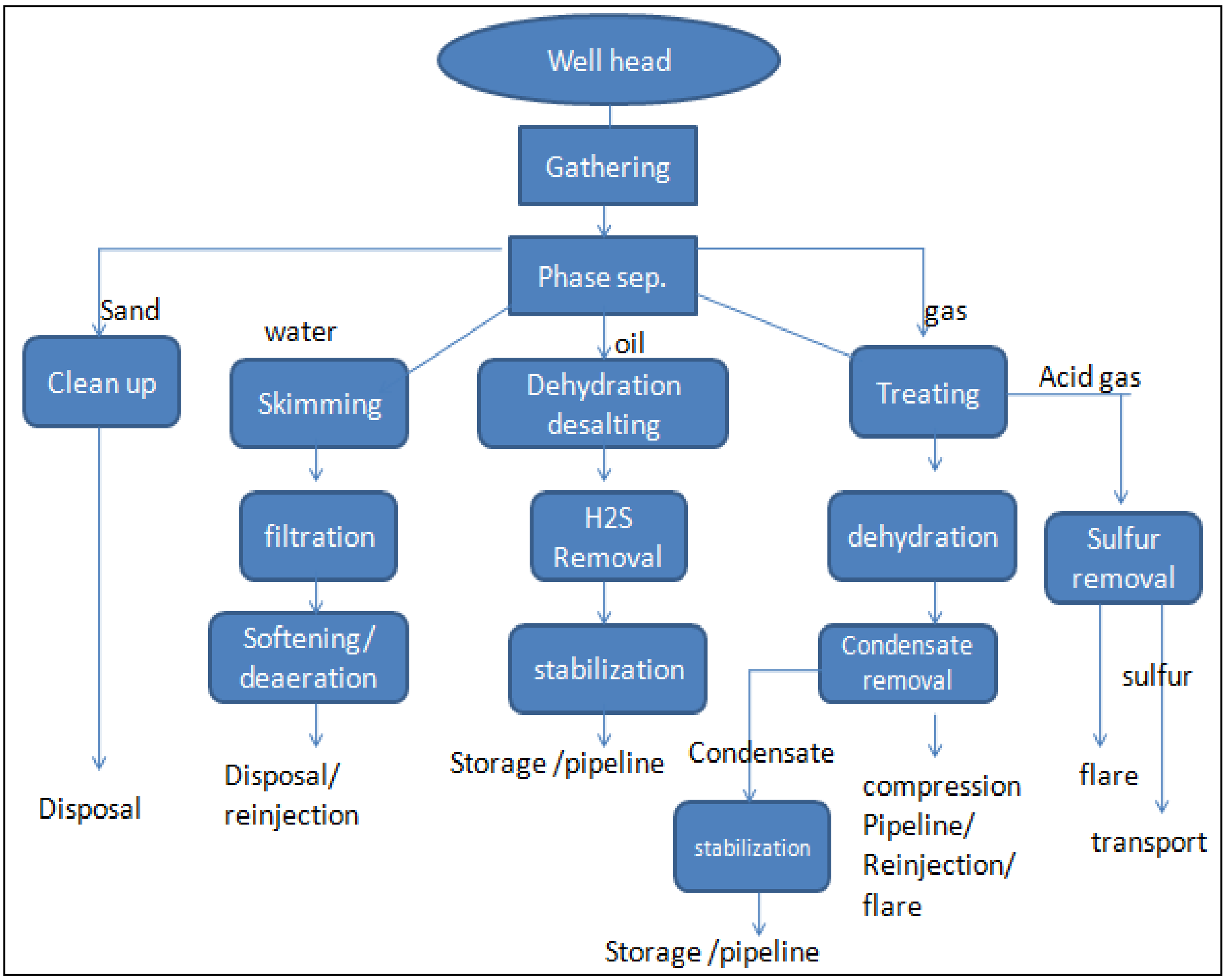

Figure 1 Oil field processing scheme[1]

After free water removal, produced oil often contains excessive residual emulsified water. Treating, also called dehydration, is required to reduce the water content to a value acceptable for transportation or sales. Dehydration should be accomplished using the most economic combination of four factors or techniques; namely, residence time, chemical addition, heat, and electrostatic fields. Diluting water must occasionally be added to reduce the salt content of the residual emulsion (i.e., the sales crude oil) to a suitably low level. Desalting performed in the refinery; overseas, desalting is sometimes performed in the field.[1]

Hydrogen sulfide in crude oil is limited to reduce handling and transportation difficulties because of its extreme toxicity and corrosiveness. Gas stripping or heating is usually used for hydrogen sulfide removal or sweetening. Crude oil stabilization refers to lowering the vapor pressure to a value that will allow safe handling and transport. Vapor pressure control is obtained by stage separation, reboiled distillation, or a combination of the two. During the stabilization some of the more volatile hydrocarbons are removed as vapor and this gas phase entrains hydrogen sulfide and other volatile sulfur compounds from the sour crude oil.

Additional sweetening may not be required. Collectively these operations are called field handling or oilfield processing .accordingly oilfield processing is defined as the processing of oil and/or gas for safe economical storage and/or transport by pipeline, tankers, or truck. Oilfields processing also include water treatment, whether produced waters for disposal and/or reinjecting, or additional injection waters used for formation flooding or reservoir pressure maintenance.[1]Some definitions of the processes shown in the graph are; separation where the vapor, oil, and water phases of produced well head stream.

Dehydration process where the water droplets or solid and water removed. Desalting process is reducing the salt content of a crude oil by diluting the entrained/emulsified water and then dehydrating. Sweetening is removing H2S and other sulfur compounds. Stabilization process is remove the most volatile components of a crude oil to reduce the Ried vapor pressure (RVP) or more currently the bubble point pressure.[1]

Oil production loop

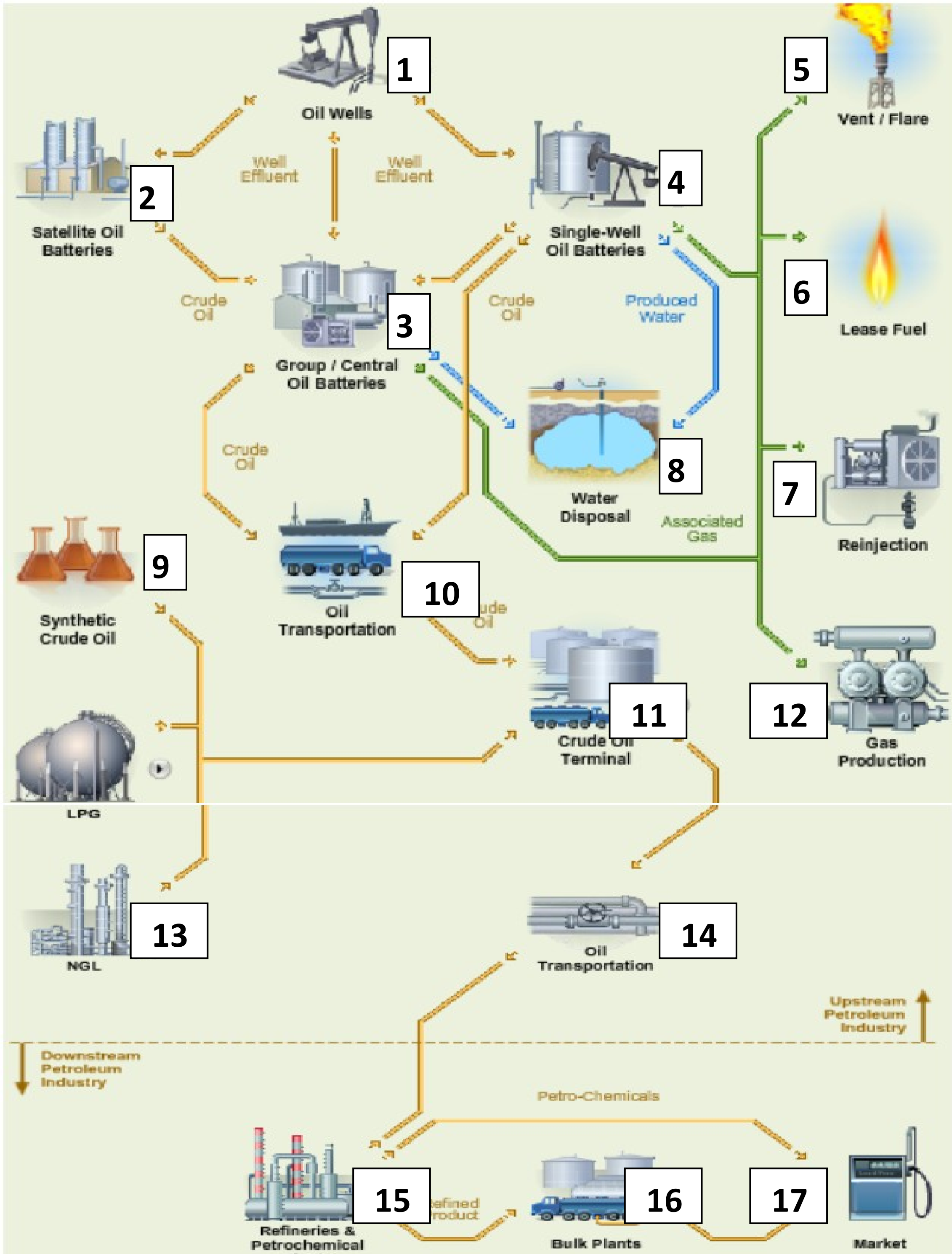

Figure 2 Cycle of oil production[2]

Definitions of the entire processing figure (2)[2]

1-oil wells: Well a hole drilled in the earth for the purpose of finding or producing crude oil or natural gas; or providing services related to the production of crude oil or natural gas such as produced water or gas re-injection.

2-Satellite oil Batteries: a small group of surface equipment (not including storage tanks) as shown in figure (3) located between a number of wells and the main crude oil battery that is intended to separate and measure the production from each well, after which the fluids are recombined and piped to the main crude oil battery for treating and storage or delivery.

3-Group central oil batteries: A production facility consisting of two or more flow-lined oil wells having individual separation and measurement equipment but with all equipment sharing a common surface location.

4-Single well oil batteries: Crude oil production facility for a single oil well or a single zone of a multiple completion crude oil well.

5-Vent/flare: Unintentional releases of oil, produced water, process chemicals and/or natural gas to the environment by human error, equipment malfunction, or a major equipment failure (e.g., pipeline break, well blow out, explosion, etc.).

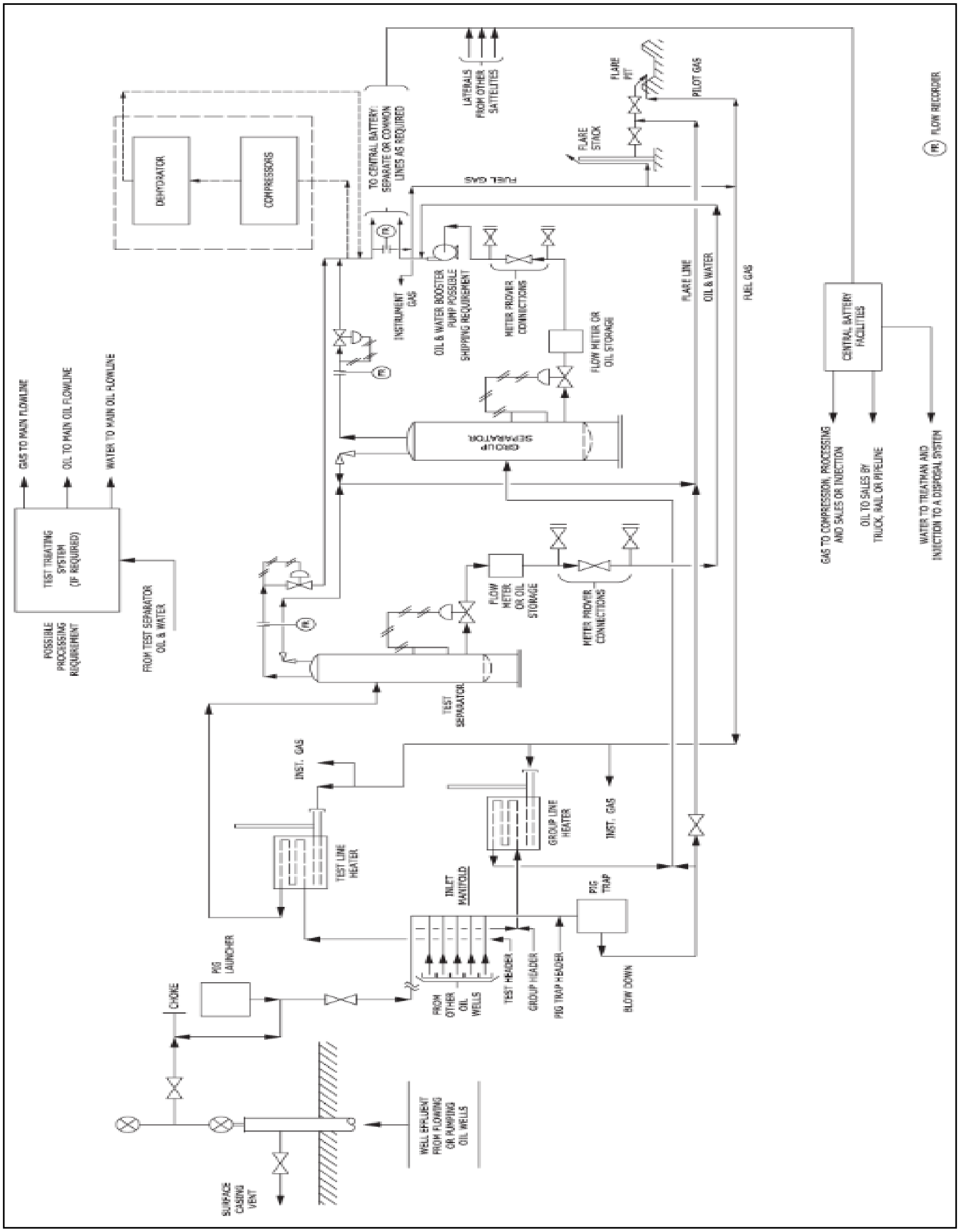

Figure 3 Satellite oil battery[2]

6-Lease fuel: Natural gas used in well, field, and lease operations (such as gas used in drilling operations, heaters, dehydrators, and field compressors engines) and as fuel in natural gas processing plants.

7-Reinjection: The injection of a gas or liquid back into the reservoir from which it originated.

8-Water disposal: A well used for the disposal of any oilfield or processing waste fluids or produced water into a reservoir or non-portable water aquifer.

9-Oil transportation: A system for transporting crude oil, NGL and LPG to upgraders and refineries.

10-Synthetic crude oil: A high quality, light, usually sweet, crude oil derived by upgrading heavy crude oil, particularly bitumen, through the addition of hydrogen or removal of carbon. It comprises mainly pentane and heavier hydrocarbons.

11-LPG (Liquefied petroleum gas): A natural gas mixture composed of mainly ethane, propane, and butanes, with small amounts of pentanes plus (C5+) in any combination. The fluid is usually gaseous under standard reference conditions but becomes a liquid under pressure.

12-NGL (Natural gas liquid-condensate): Water and hydrocarbons that boil above ambient temperature and pressure that condenses out of natural gas due to changes in temperature, pressure, or both, that remains in liquid form at atmospheric pressure storage condition. In other words, because natural gas is not a pure product, as the reservoir pressure drops when non-associated gas is extracted from a field under supercritical pressure and temperature conditions the higher molecular weight components may partially condense upon isothermal depressurizing an effect called Retrograde Condensation. The liquid thus formed may get trapped as the pores of the gas reservoir get deposited.

13-Crude oil terminal: Plant and equipment designed to process crude oil or gas to remove impurities and water.

14-Gas production: Total natural gas output from oil and gas wells.

15-Refineries petrochemical plants: A plant as shown in figure (4) where crude oil is separated by distillation into many boiling range fractions each of which are then converted by various secondary processes often employing catalysts and further fractionation or purification steps such as cracking, reforming, alkylation, polymerization and isomerisation, into usable products, blending stocks or feed stocks for other processes.

The secondary unit products are combined in the product blenders to meet specifications of finished commercial products commonly including but not limited to ethylene, propylene, benzene, toluene and xylenes (for petrochemicals); grades of gasoline, diesel and fuel oils; waxes, lubricants and greases; residual fuel oil, asphalt and petroleum coke.

16-Bulk plants: A storage facility used by a distributor or supplier in the wholesale segment of the industry which has the storage capacity to receive and distribute petroleum products in bulk.

17-Market: The industrial, commercial and residential demand for petroleum products.

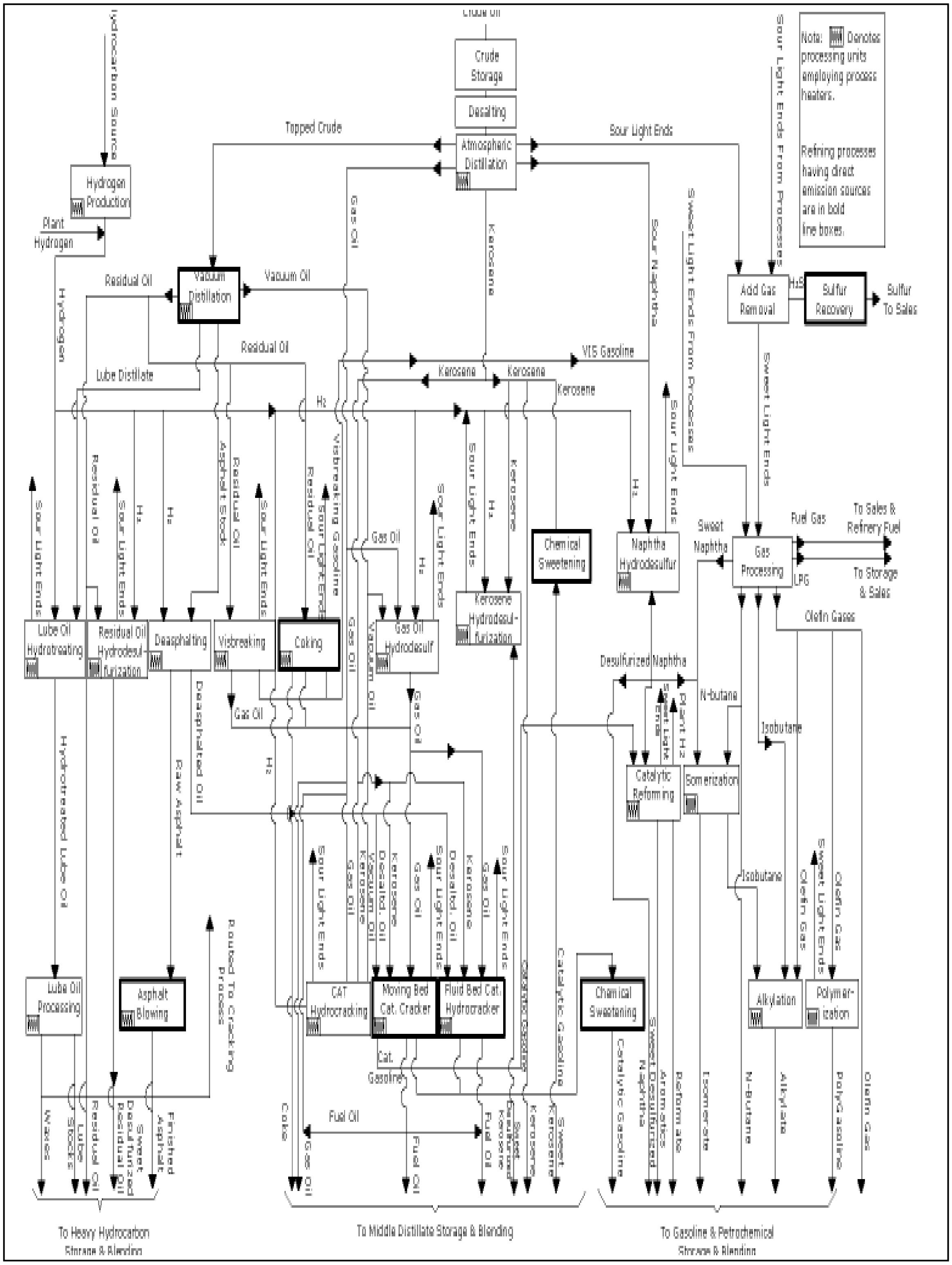

Figure 4 Integrated petroleum refinery[2]

Processing scope[1]

The scope of processing depends on the nature of the well fluids, the location and size of the field, availability of gas and electricity, the comparative sales prices for gas and crude oil. The nature of the well stream has an impact on the surface facility design, including reservoir drive, the water oil ratio(WOR), the gas oil ratio (GOR) or alternatively the gas liquid ratio(GLR), and the of the crude oil (°API, Pour point, etc). The type of the drive determines how the ratios of the gas, oil, and water are expected to vary during the field life. If large increases in water production are expected, the suitable measures should be taken such as determined of the size factor. In the Middle East the size factor is 2 because of the large flows (400,000 to 750,000 BOPD). However, high- pressure, high -°API crudes require vastly different processing than low-°API crudes produced by stream drive. For low gas oil ratio (GOR) oil handling process it is simpler than high gas oil ratio. For low GOR process the dissolved natural gas is released in one or more separators followed by emulsion treating and storage. Then, the oil metered as it is pumped into the carrier, whether it's tanker, barge, or pipeline. And the water is cleaned up for the local discharge. Gas may be vented or flared if no compression facilities or pipeline is available. But, for the high GOR oil the process is more complex, because the large amount of oil and gas require that each be recovered for sales. Also, stage separation of oil and gas with gas recompression is practiced. Both streams of oil and gas may require further processing before sales such as removal of hydrogen sulfide and water. The oil may require emulsion treating and/or desalting. The process for Dry, sweet gas is not complicated where the condensate natural gas liquid is separated first then followed with compression if necessary, then glycol dehydration, metering, and delivery to the pipe line. Hydrocarbon condensate may be injected into the gas pipe line or transported separately.

1.3 Measured properties – production stage

Measurement has two sides' quantity and quality. Measurement of oil is very important to the profitability of any operation, inaccuracies can have bad consequences. Any measurement technology needs to be accurate enough to gain much information about the production performance. The measurement of quantity is well understood and regulated by international laws. Standards exist that define accuracy, repeatability and acceptable uncertainties for a measurement system. The most important measurement standard for the petroleum industry is the API Chapter 5. Many efforts were done, to increase accuracy by finding more precise measurement techniques. These kinds of measurments must be done in the early life of the field production to evaluate initial hydrocarbon in place which called dynamic method and by using these data other properties can be estimated using material balance equation. Later on of the field life repeating measuring the properties in the lab will be according to the necessity. These measurements depend on the samples that has been taken from the field or as they call them cores in petroleum industry. Labs measurements can be divided into two categorize:

1- Conventional core analysis.
2- Special core analysis.

1.3.1 Viscosity measurments

Viscosity measurement is one of the conventional core analyses. It is one of the most important properties of a fluid and plays a prominent role in the petroleum industry. Small changes in viscosity can have a dramatic impact on the properties of petroleum fluids. It is determined by measuring the time it takes for a volume of fluid to flow under gravity through a calibrated glass capillary viscometer, Although it sounds simple, achieving the high accuracy and precision required by the industry is an extremely formidable task. There are many factors that affect the precision of this test method. In economic terms, an error of one percent product viscosity that causes a blend adjustment can easily result in increasing product cost by a penny per gallon. For a large lubricant manufacturer, this can amount to $1 million or more in lost revenue per year. The viscosity of crude oil affects our ability to pump it out of the ground. Viscosity measurement done at two stages in the drilling operation and after completed the well and the well ready to production. The important of measure the viscosity of the crude oil in the lab after taking representative sample of the fluid is very important for the surface facilities design at the very beginning of the field production. And for every new well a samples must be taken to have a routine measurement. However, at the lab there are many instruments with different techniques to measure the viscosity as following devices.

1.3.1.1 Gas Chromatography

Gas chromatography as shown in figure (5) uses a heating process to evaporate crude oil components and collect them in a chromatography paper, which absorbs different mixtures based on their absorbency rates. This method, also carried out by engineers in a lab, identifies the components and their viscosity within a short period of time by comparing the results with previous tests, but doesn't provide the exact values of molecular weight and density. With gas chromatographs gas mixture can be analyzed with high accuracy for quality. Liquid mixtures can also be analyzed providing they can be transferred to the vaporous state. Used in analytic chemistry for separating and analyzing compounds that can be vaporized without decomposition.

Figure 5 Gas chromatography

1.3.1.2 Boiling Point Test

The tests are used to characterize the oil with respect to the boiling points of its components as Crude oil components have different boiling points. The boiling point test method carried out in a laboratory by petroleum engineers, subject crude oil to high temperatures and records when each component reaches its boiling point. The lower the temperatures required for separating the crude into its components, the lower the viscosity of the crude oil, and vice versa. In these tests, the oil is distilled and the temperature of the condensing vapor and the volume of liquid formed are recorded. This information is then used to construct a distillation curve of liquid volume percent distilled versus condensing temperature. The condensing temperature of the vapor at any point in the test will be close to the boiling of the material condensing at that point. For a pure substance, the boiling and condensing temperature are exactly the same. For a crude oil the distilled cut will be a mixture of components and average properties for the cut are determined. Table 1 shows typical results of a TBP test.

In the distillation process, the hydrocarbon plus fraction is subjected to a standardized analytical distillation, first at atmospheric pressure, and then in a vacuum at a pressure of 40 mm Hg using a fifteen theoretical plates column and a reflux ratio of five. The equipment and procedure is described in the ASTM56 2892-84 book. It is also common to use distillation equipment with up to ninety theoretical plates. Usually the temperature is taken when the first droplet distills over. The different fractions are generally grouped between the boiling points of two consecutive n-hydrocarbons, for example Cn-1 and Cn. The fraction receives the name of the n-hydrocarbon. The fractions are called hence, 18 single carbon number (SCN). Every fraction is a combination of hydrocarbons with similar boiling points. For each distillation cut, the volume, specific gravity, and molecular weight, among other measurements, is determined. Other physical properties such as molecular weight and specific gravity may also be measured for the entire fraction or various cuts of it. The density is measured by picnometry or by an oscillating tube densitometer. The average molecular weight of every fraction is determined by measuring the freezing point depression of a solution of the fractions and a suitable solvent, e.g., benzene. If the distillate is accumulated in the receiver, instead of collected as isolated fractions, the properties of each SCN group cannot be determined directly. In such cases, material balance methods, using the density and molecular weight of the whole distillate and the TBP distillation curve, may be used to estimate the concentration and properties of the SCN groups57. A typical true boiling point curve is depicted in figure 1. The boiling point is plotted versus the collected volume. There are several ways of calculating each fraction boiling point.

1.3.1.3 Rotational Viscometer[6]

One type of the rotational viscometer is Stabinger viscometer as illustrated in figure (6) a machine that measures the viscosity of crude oil based on the principle that viscosity can be determined by the force required to turn an object in a fluid. A viscometer rotates a disk in the fluid at a certain speed; the torque required to achieve the rotational speed is proportional to the viscosity of the crude oil. The Stabinger measuring wide viscosity and temperature range with a single system.

Figure 6 Stabinger viscometer

1.3.1.4 Capillary viscometer

The equipment as shown in figure (7)is used for kinematic viscosity measurement. Using the equipment within the range of 20 to 100°C, temperature is controlled to 0.01°C; above 100°C temperature is controlled to 0.03°C.

Figure 7 Capillary viscometer

1.3.1.5 Thermodynamic Properties Prediction

This kind of measuring the viscosity based on calculations. Petroleum engineers use critical properties such as pressure and molecular weight to determine the viscosity behavior of crude oil. They measure and compare these characteristics with past experiments before checking the results for similarities. For instance, if past experiments indicate that crude oil of a certain molecular weight had a viscosity of 1000 centipoises when pumped at a pressure of 30,000 pounds per square inch, engineers can determine the possible viscosity of crude oil of a similar molecular weight pumped at a pressure of 60,000 pounds per square inch.

1.3.1.6 Oscillating Piston Viscometer

Measurements are taken whereby a sample is first introduced into the thermally controlled measurement chamber where the piston resides. Electronics drive the piston into oscillatory motion within the measurement chamber with a controlled magnetic field. A shear stress is imposed on the liquid (or gas) due to the piston travel and the viscosity is determined by measuring the travel time of the piston. The Oscillating Piston Viscometer technology as shown in figure (8) has been adapted for small sample viscosity and micro-sample viscosity testing in laboratory applications. It has also been adapted to measure high pressure viscosity and high temperature viscosity measurements in both laboratory and process environments. The viscosity sensors have been scaled for a wide range of industrial applications such as small size viscometers for use in compressors and engines, flow-through viscometers for dip coating processes, inline viscometers for use in refineries, and hundreds of other applications. The measurement function of the viscometer is fully automatic to reduce measurement errors. An electromagnetic piston maintains a continuous fresh sample while under test and requires a small sample volume.[6]

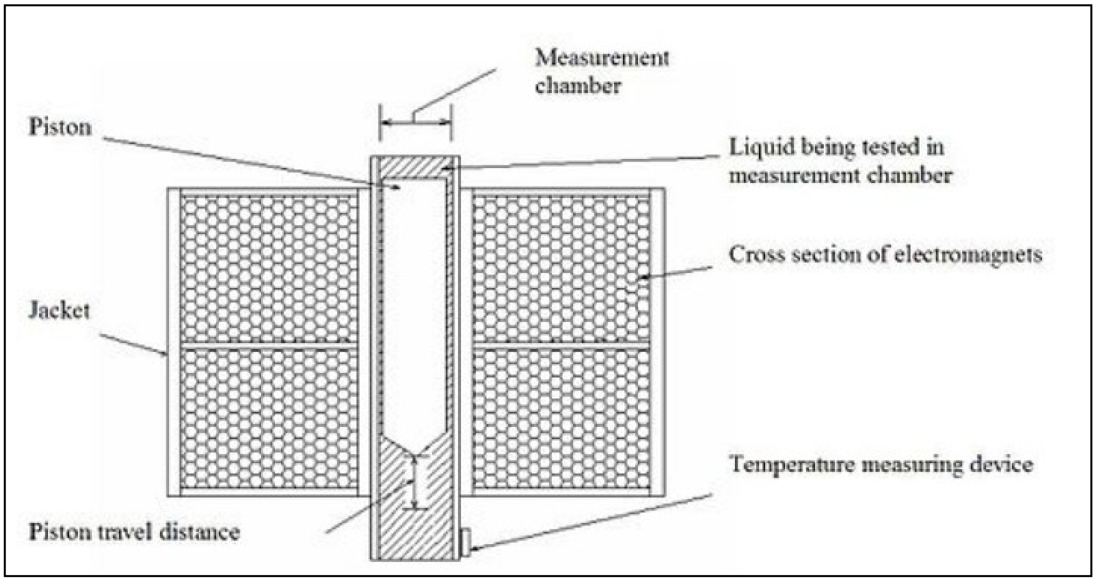

Figure 8 Oscillating piston viscometer[6]

1.3.2 Density measurments

The density measurement done as a routine measurement for each well to classify the crude oil based on the API. In addition to that it can be used for other calculations and for market purposes. There are many types and shapes for the Coriolis meters as shown in figure (9). These meters Can be used for high pressure or low pressure.

Figure 9 Coriolis meters type's devices[28]

1.3.2.1 Micro Motion Coriolis meters

Coriolis meters Used to measure oil density in the oil field online Micro Motion and the fluid flow, the inventor of the first practical Coriolis flow meter. Micro Motion is the leading concentration measurement technology available today.

The typical benefits of using coriolis meters as densitometers are

- High accuracy (± 0.0005 g/cc) and
- repeatability (± 0.00002 g/cc) well within API Ch.14.6 recommendations
- High sensitivity to density changes
- Eliminated requirement for separate density computing electronics (safe area mounted)
- Less sensitive to Vibrations

- No flow contact indicates incorrect representation of density measurement
- Low maintenance since few system components flow sensor has no moving parts in the flow stream that ensures long life even if sand or small particles pass through the meter Temperature corrected oil and water volumes. The Micro Motion Coriolis devices have many types used for different purposes such as:

1) Wire Coriolis Flow and Density Meters

Emerson’s new Micro Motion 2-wire Coriolis meters with MVD Technology as shown in figure(10) extends highly accurate mass flow and density measurement to loop-powered applications eliminating the need for additional power wiring.

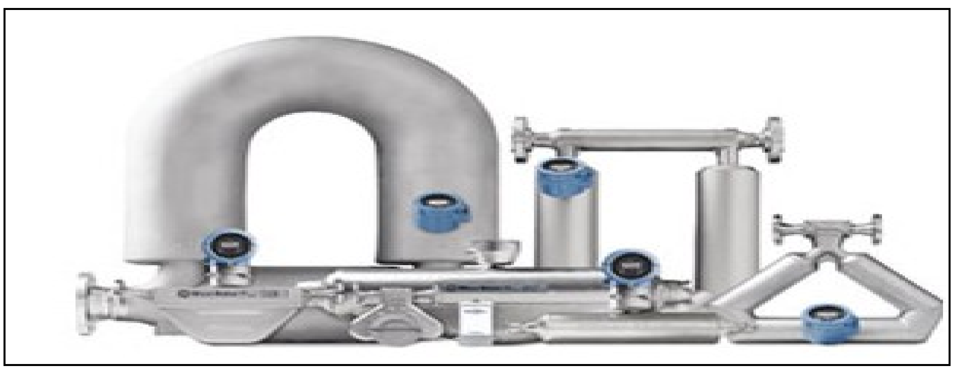

Figure 10 Wire coriolis flow and density meters[14]

2) ELITE Peak Performance Coriolis flow and density meters

Micro Motion ELITE Coriolis meters are the leading precision flow and density measurement solution offering the most accurate and repeatable mass measurement for liquids, gases, or slurries. ELITE meters offer the most accurate measurement available for virtually any process fluid, while exhibiting exceptionally low pressure drop. As shown in figure (11).

Figure 11 Elite peak performance density meters[14]

The advantages in the most challenging applications are

- Industry standard for custody transfer and critical process control
- Best two-phase flow capability for batching, loading, and entrained air applications
- Immune to fluid, process, or environmental effects for superb measurement confidence
- Available in numerous materials of construction such as, 316L, 304, C22, and Super Duplex
- Micro Motion's newest offering, the CMFHC3Y, is a high capacity meter in Super Duplex for 8-10" lines.

- This new material is ideal for chloride corrosion and pressures up to ANSI CL900 (2320 psi).

3) F-Series High Performance Compact Drainable Coriolis Flow and Density Meters

Micro Motion F-Series Coriolis meters as shown in figure (12) are intended for highly accurate mass flow, volume flow, and density measurement in applications that require a compact, drainable design. The F-Series is also available for high temperature, high pressure, and corrosive applications. As shown in next figure (12).

Figure 12 Elite peak performance density meters[14]

1.3.3 Solution gas oil ratio

Solution gas oil ratio defined as the number of standard cubic feet of gas dissolved per barrel of tank oil. It can be calculated using standing correlation equation (1) and (2).

$$Rs = \gamma g*((P/ 18(10)\ \hat{}\ \gamma g)\ \hat{}\ 1.204) \quad \textbf{(1)}$$

$$Yg = 0.00091\ T - 0.0215\ \rho o \quad \textbf{(2)}$$

Whereas:

RS = solution gas oil ratio (SCF/ STB)

T= Temperature, f

P= pressure, psi.

1.3.4 Crude oil flow rate measuring:

Produced crude oil is measured prior leaving the well site, as required by law as shown in figure (13). Table (2) in the appendix give a Characteristics of Meters for Liquid Measurement. The gross volume from which the royalty share is calculated is based on this oil and gas measurement. Customary industry standard is that the operator verifies the measurements of the first purchaser through a rechecking the levels in oil storage tanks for oil[4]. Meters located after the test separators in the filed to measure the quantity of the flow of the producing wells and it is necessary to measure the fluid quantity before transportation .then the crude oil metered once again before send refinery and before lifting (shipment). And meters also considered as one of the components of the lease automatic custody transfer. The crude oil after being produced contains some impurities. The first step toward accurate crude oil measurement is to remove any free water and sediment which is done using free water knockout, Gun barrel separator or three phase separator. Crude oil is measured in one of two ways, depending on aggregate volume available for measurement.

For smaller volumes in the range of 1-100 BOPD let's say, the oil generally flows into an atmospheric storage tank and is held there until sufficient quantity is accumulated to make a "run". A run is simply the act of removing the oil from the lease location, and taking it offsite for further treatment. When a run is ready to be made, the first step is to do a shake-out test. A sample of the oil is taken, and placed in a portable

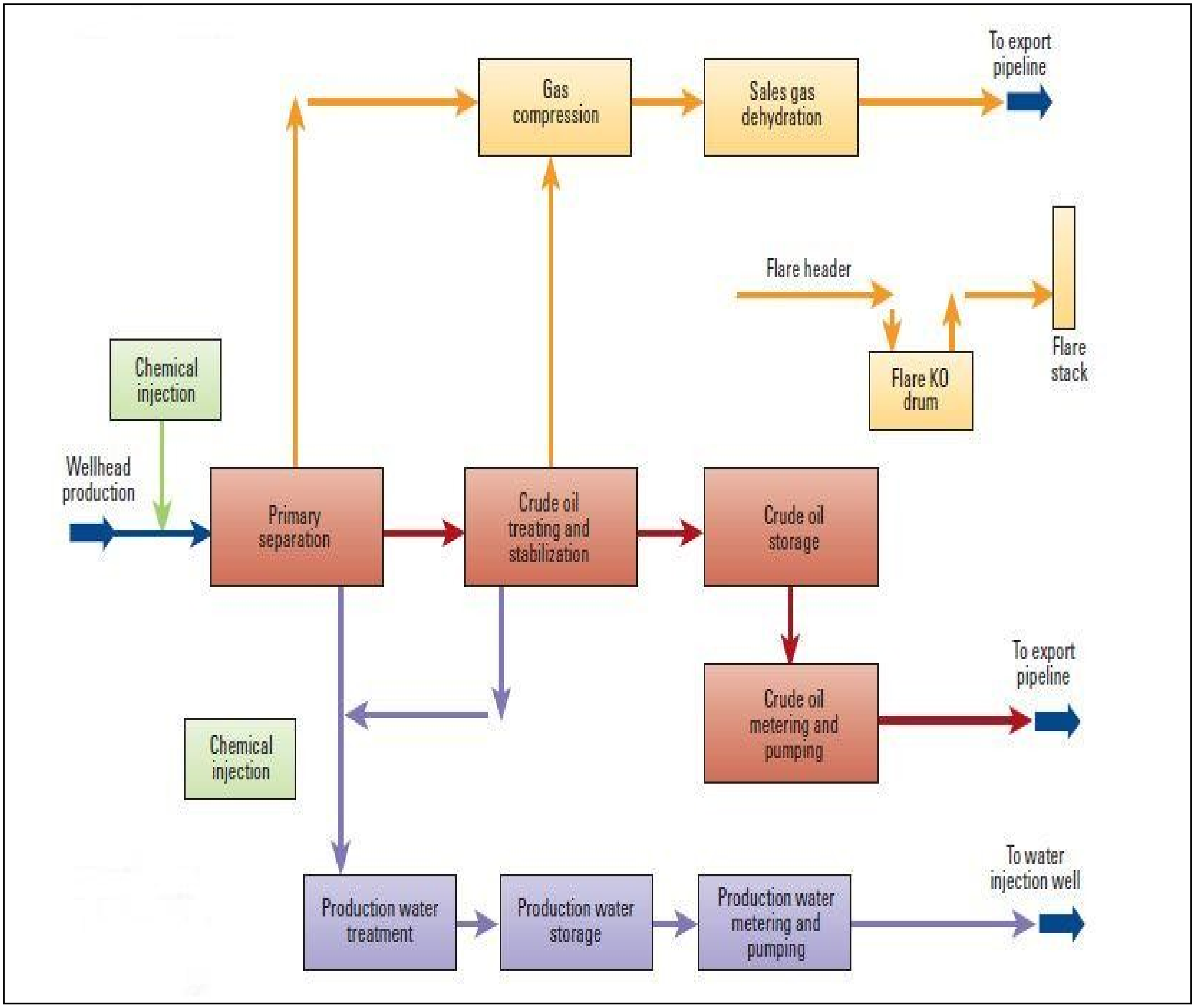

Figure 13 Early production facility and metering positions[26]

Centrifuge forces entrained impurities to separate from the oil. The results will be used to adjust the final volume on which all owners are paid.[11] To measure the volume of a run, a measuring strap with a weight on the end is lowered into the oil tank, and an initial reading is taken. Next, a valve is opened which allows the oil to flow by gravity into a pipeline or truck, whichever the case may be. When the tank is nearly emptied, the valve is shut and a second strap reading is taken. The difference between the two tank levels (readings) is now used to calculate the exact volume of oil that has been removed. The person making the run now completes a field run ticket which is made a part of the accounting records for this transaction.

For larger volumes in the range of 100-1000 BOPD let's say, the oil generally flows through an automated system called a LACT unit, which stands for Lease Automatic Custody Transfer. This system provides for the automatic measurement, sampling, and transfer of oil from the lease location into a pipeline. As you can imagine, a system of this type is applicable where larger volumes are being produced, and must have a pipeline available in which to connect. There are fundamentally two types of flow measuring devices; Direct Measurement Devices and Inferential Measurement Devices. Direct measuring devices are devices that use the fluid properties as direct measuring parameters to determine the fluid flow rate. Such parameters are mass, density, viscosity temperature, pressure etc. such as Positive Displacement Meters and Mass Flow Meters.

Inferential measuring devices use parameters other than the fluid properties, such as electronic pulse counts, meter factors, system factors, linear and rotational velocities components of measuring devices to infer the fluid flow rate. Examples are Turbine, Hellicoidal, Orifice Plate, Vortex, Venturi and Ultra Sonic Flow Meters. Other measurement devices associated with fluid flow are temperature, static and differential pressure measuring devices. Crude and hydrocarbon product measurements consist of two types Volumetric and Mass Flow.

Accuracy of meters

To obtain the required accuracy, the meters are calibrated. The most common method is a prover loop. A prover ball moves though the loop, and a calibrated volume is provided Meters differ in their design and the mechanism as shown in table (1), function and capabilities and differ in the position in the field as shown in figure (13).

Fluid measurement is a very important instrument for Reservoir management, Production allocation and custody transfer to the transporters or the customers. Many efforts were made in the past to increase reliability and accuracy of measuring devices. With multiphase measurement it is possible to measure flow rates and water cuts without necessarily having to separate the fluids from the well. The main types of meters used in petroleum industry are Turbine meters, Orifice meters and Positive displacement meters, but there are more types of meters as the following; Differential pressure (DP) flow meters, Turbine or propeller meters, ultra sonic meters, ultra sonic meters, coriolis mass meters and Electric magnetic flow meters as shown in figure (14).The most three popular flow meters usage is shown in figure (15).

Table 1 Major types of the flow meters[9]

Flow meter name	types
Differential Pressure	Orifice Plate, Venturi Tube,Flow Tube, Flow Nozzle, Pitot Tube, Elbow Tap Target, Variable-Area
Positive displacement	Reciprocating Piston, Oval Gear, Nutating Disk, Rotary Vane.
Velocity	Turbine, Vortex Shedding, Swirl, Canada Effect & Momentum Exchange, Electromagnetic, Ultrasonic, Doppler, Ultrasonic, Transit-Time.
mass	Coriolis, Thermal.
Open- channel	Weir, Flume.

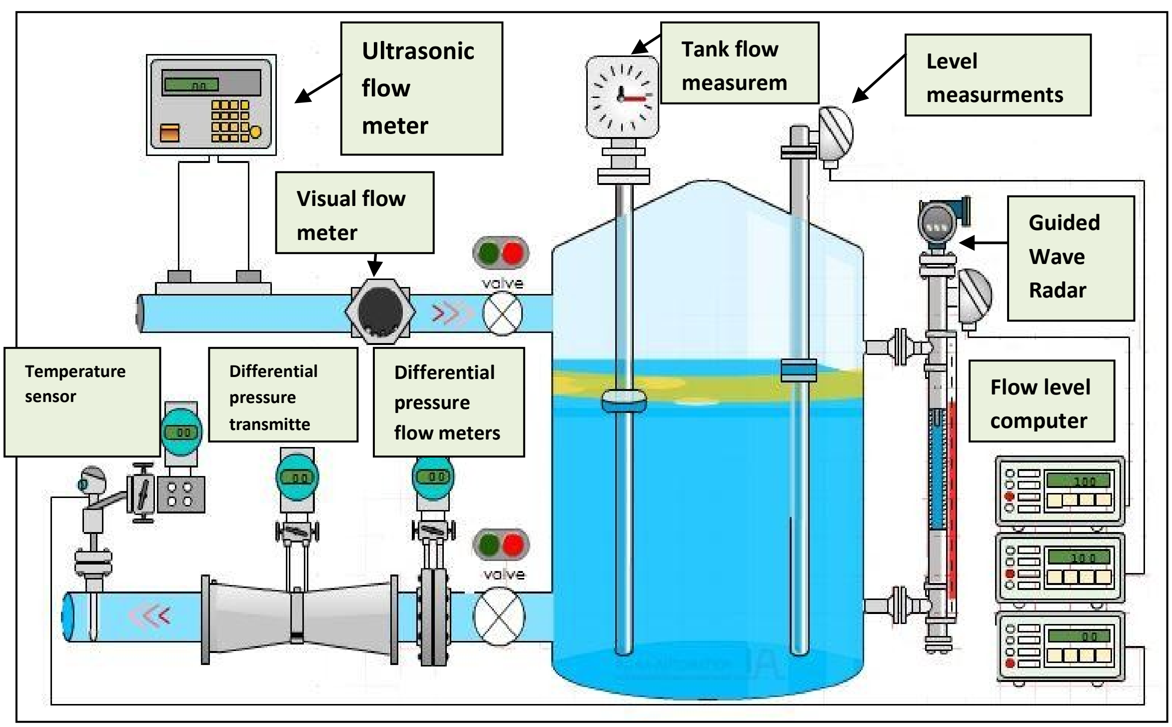

Figure 14 Major types of meters instrumentations and their positions

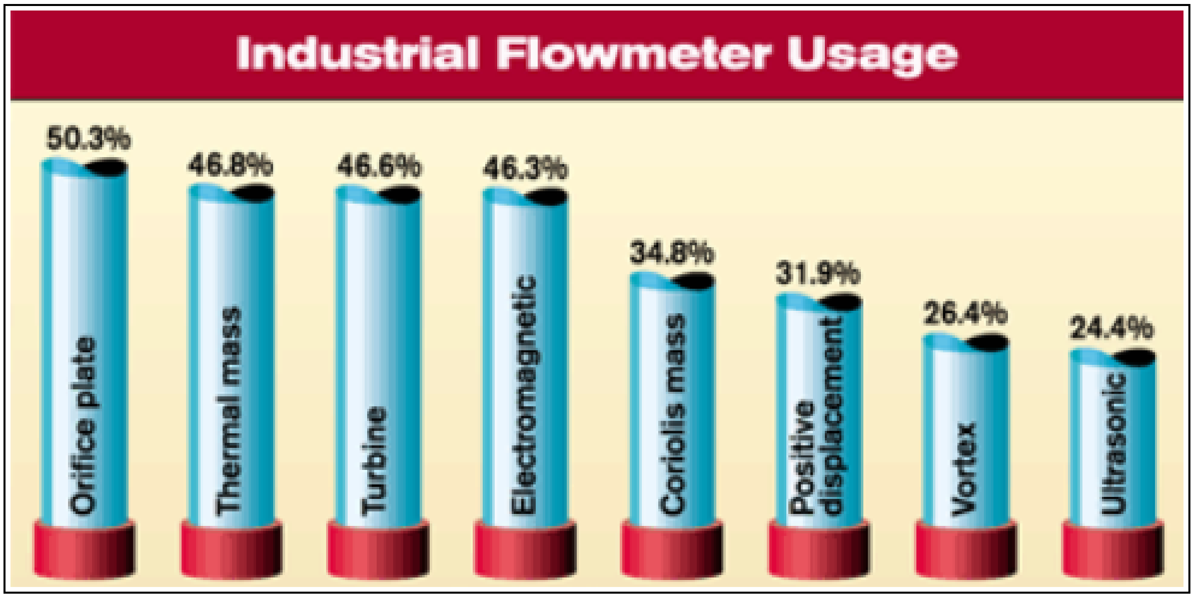

Figure 15 Flow meter types usage percents [9]

1.3.4.1 Ultra sonic flow meters(Intra Sonic)

With the ultra sonic measurement the delay time between two ultra-sound transmitters and receivers is measured between a static product and a flowing product. With flowing product the ultra sonic ray which runs against the flow of product will meet the receiver with a time delay. The time delay is directly proportional to the flow velocity of the media and this means it is proportional to the volumetric flow. The Ultrasonic flow meters are highly dependent on fluid properties such as sonic conductivity, density, temperature, etc. Moreover, non uniformity of particle distribution in the pipe cross section results in a computed velocity that is not very accurate. In other words, No pressure drop occur with this meter but the main difficulty is the accuracy of sound velocity measurement required to pick up the much smaller flow velocity.

Uses include natural gas measurement uses include natural gas measurement in large pipes, sewage and slurries, and corrosive liquids.

Ultra sonic sensors types

Ultrasonic transit-time differential measurement can be employed to measure the volume flow of any liquid, regardless of electrical conductivity. Two different types of sensors enable users to meter flow cost-effectively, economically and flexibly, anywhere in the process and at any time clamp-on sensors and inline sensors as shown in figure (16). The range of sensors is extensive, so widely differing sets of requirements can be satisfied. Clamp-on sensors retrofit to the outside of existing pipes, e.g. for verifying other meters or for temporary flow measurement (accuracy: typically ±2%). Inline sensors for direct installation in the pipe meet higher accuracy requirements (±0.3 to 0.5%).

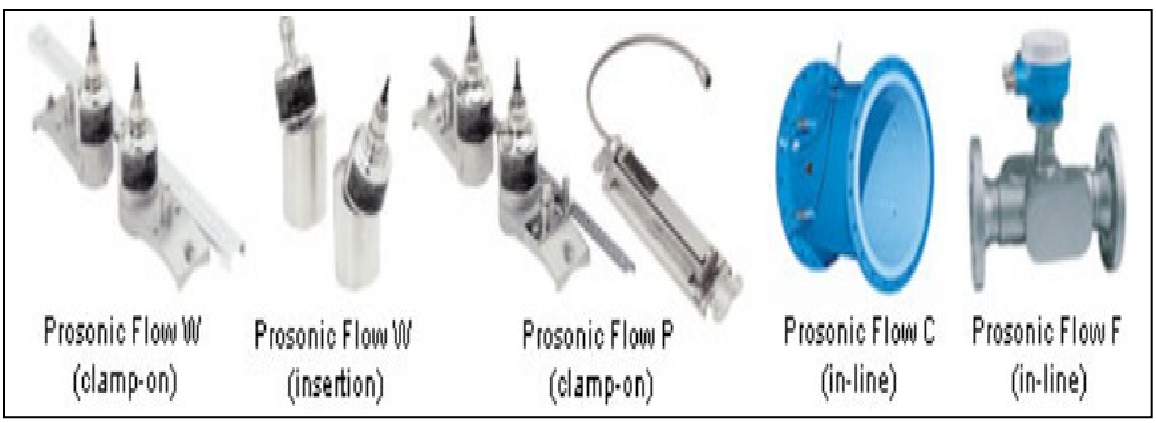

Figure 16 Ultra sonic sensors[29]

1.3.4.2 Electromagnetic flow meter

Magnetic flow meters are based on Faraday's Law of Magnetic Induction. In a magnetic flow meter, the liquid acts as a conductor as it flows through the pipe. This induces a voltage which is proportional to the average flow velocity - the faster the flow rate, the higher the voltage. This voltage is picked up by sensing electrodes mounted in the meter tube and sent to the transmitter which takes the voltage and calculates the flow rate based on the cross sectional area of the meter tube.

Application of electromagnetic flow meter

1. Very corrosive liquids ; Acids, caustics and corrosive chemical additives are isolated from the meter by inert linings and electrodes
2. Conductive Liquids; Liquids where conductivity is at sufficient levels to induce measurable voltage (slurries and water).
3. Distribution and power station, chemical, nuclear, and process industries.

Electromagnetic flow meters products

- Krohne optiflux 4000 electromagnetic flow sensor krohne optiflux Magnetic flow meters as shown in figure (17) are intended to measure the flow of electrically conductive liquids in full pipes. The pressure drop through the meter is minimal, (equal in magnitude to a piece of pipe of the same diameter and length) making it an excellent choice for low pressure systems. There are no moving parts or obstructions in the fluid stream so the meter is virtually maintenance free and suitable for fluids containing abrasives.

Figure 17 Krohne optiflux magnetic flow meter[30]

1.3.4.3 Positive displacement flow meters

Used for fluid flow rate measurements and one of the main types of the flow metering. Measures flow rate (instantaneous, cumulative) by counting the number of volumes through the meter. Positive displacement flow meters measure the volume or flow rate of a moving fluid or gas by dividing the media into fixed, metered volumes.

General Description

The AW Gear meter's positive displacement gear flow meters as shown in figure (18) are similar in design to the gear pump. The principle of operation is reversed; instead of the gears driving the medium, the medium drives the gears. A non intrusive hall effect sensor detects the movement of the gear and as each gear tooth passes the sensor a square wave pulse is produced and a discrete volume of liquid is measured. The resulting pulse train is proportional to the actual flow rate and provides a highly accurate representation of the fluid flow. All meters are designed with highly wear resistant moving parts to provide exceptionally long service life. The position of installing the meter is shown in figure (19).

Figure 18 Positive displacement flow meters[31]

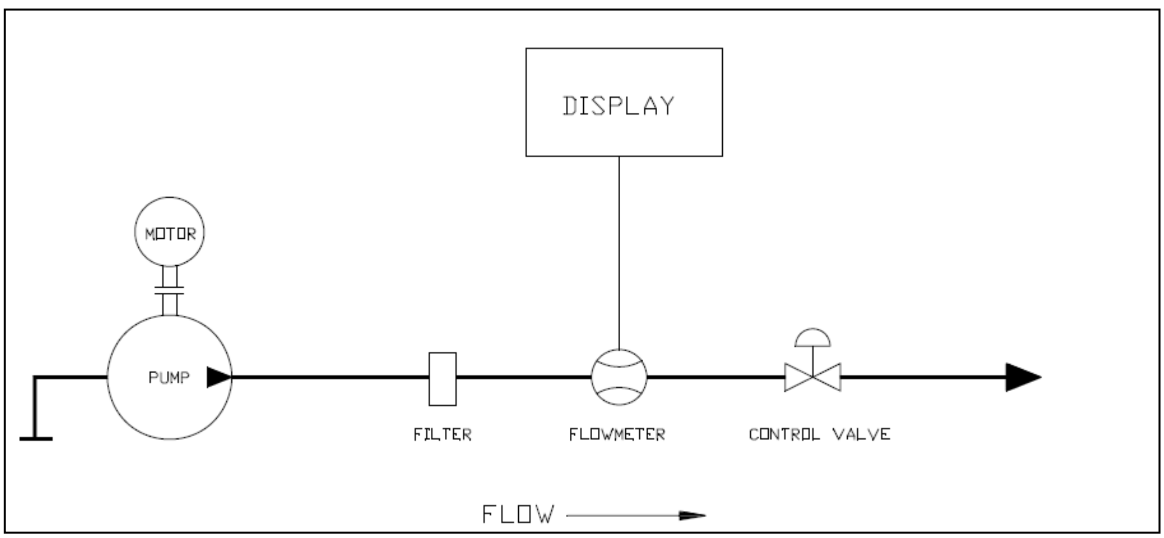

Figure 19 Installation position of positive displacement meter[42]

The following table (2) is representing Trouble Shooting Guide for the positive displacement meters

Table 2 Trouble Shooting Guide for the positive displacement meters[42]

TROUBLE	POSSIBLE CAUSE	SOLUTION
Meter indicates lower than actual	-Viscosity of fluid is <30cst. -Excessive pressure differential across meter causing gears to bind. -Debris in measuring chamber. -Upper housing has dimple from over tightening sensor.	-Decrease the K-factor by percent error. -Reduce flow rate, reduce fluid viscosity. -Clean meter, change or add filter. -Replace upper housing.
Meter indicates Higher than actual.	-Air in lines. -Electro-magnetic interference. -Reverse fluid flow.	-Add air eliminator. -Ground flow meter and all electronics. -Add check valve.
Indicator shows flow when there is no flow.	-Fluid oscillates. -Electro-magnetic interference.	-Check pump, add check valve, increase back pressure. -Ground flow meter and all electronics. Use shielded cable and relocate away from electrical noise.
No flow indication.	-No fluid flow. -Debris in measuring chamber or gears. -Sensor not installed properly. -Faulty wiring. -Faulty sensor. -Upper housing has dimple	-Check pump. -Clean meter, change or add filter. -Check sensor is installed to hand tight. Review sensor guide. -Check sensor connection and readout connection. -Replace sensor. -Replace upper housing.

	from over -tightening sensor.	
Erratic system indication.	-Ground loop in shielding. -Pulsating fluid flow.	-Ground shield one place only. Re-route cables from electrical noise. -Add pulse dampener.

Advantages of positive displacement meters

- This meter has the ability to maintain consistent accuracy despite changing viscosity conditions, with accuracy of +0.5% of reading.
- Flow may be bi-directional, without damage to internal parts and is offered in six different flow ranges (0.003 to 120.0 GPM).
- The meters produce good resolution and high accuracy at low flow rates, offering an affordable replacement for older turbine technology.
- Installation is easy because there is no need for straight run piping upstream or downstream of the flow meter.

Disadvantages of positive displacement meters

- 1 year warranty period.
- Do not dry paint lines using only pressurized air as this will lead to premature wear.

1.3.4.3 Turbine meter

Measure the flow rate (instantaneous or cumulative) by converting fluid velocity into rotational velocity. The rotational speed of the turbine is proportional to the volume flow. Gentrified meters are available due to its high accuracy. With additional temperature and a density measurement certified mass measurements can be carried out with a volume corrector. Turbine flow meters as illustrated in figure (20) considered for metering gas in case of the well contains oil and gas. Turbine Flow Meter Applications are fuel oil and liquefied gases. There are type “F”, “F-D”, “E” they differ in whether they have a mechanical shaft or not.

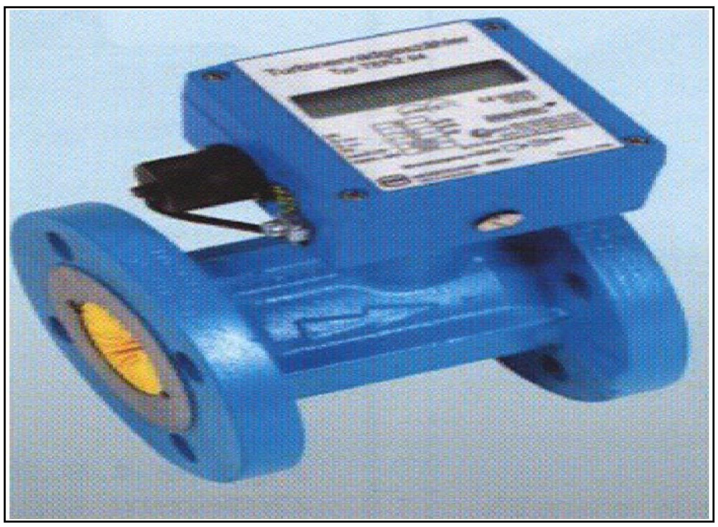

Figure 20 Turbine flow meters[5]

Turbine flow meters features

- Flow ranges from 0.08 to 5,000 GPM
- Accuracy ± 1% of actual flow
- Pressure rating up to 5,000 PSI
- 316 stainless steel body
- Economical cost

- Thirteen different flow ranges available

Advantages of turbine meters

- The sturdy construction of this turbine flow meter means high performance and longer service life at an affordable price.
- The TRG Series flow meter comes with a standard NPT end connection for universal applications
- This meter is capable of measuring flow in line sizes from 1/2" to 10"
- This meter can provide displayed flow rate, totalization, current or voltage outputs through a variety of compatible electronics.

Application of the turbine meters

- Maximum bar 100 bar.
- Measuring range 10- 25000 m3/h

1.3.4.5 Mass Coriolis flow meters

Mass Coriolis as illustrated in figure (21) enhanced sensitivity improves signal to noise ratio for increased flow ranges and improved accuracy at lower flow rates. The Coriolis meter is ideal for the measurement of flow, density and temperature of liquids and slurries, such as aggressive or contaminated, sanitary or particle-filled fluids.

Mass Coriolis flow meters features

- Accuracy of ± 0.10% of reading ± zero stability.
- Maximum temperature 400° F, 204° C
- 316L stainless steel flow tubes

- Pressure rating up to 2900 PSI, 100 bar
- No moving parts
- Ability to measure flow, density and temperature

Figure 21 Mass Coriolis flow meter[33]

1.3.4.6 **Multi-phase flow meters**

Conventional single-phase metering systems require the constituents or "phases" of the well streams to be fully separated upstream of the point of measurement. For production metering this requirement is usually met automatically at the outlet of a conventional process plant, since the main purpose of such a plant is to receive the sum of well streams in one end and to deliver (stabilized) single phases ready for transport (and hence also measurement) in the other end. Single-phase metering systems normally provide high-performance measurements of hydrocarbon production. The need for multiphase flow metering arises when it is necessary or desirable to meter well streams upstream of inlet separation and/or commingling. Multiphase flow measurement technology may be an attractive alternative since it enables measurement of unprocessed well streams very close to the well. The use of MPFMs may lead to cost savings in the initial installation. Some MPFMs work better in certain applications than others. Hence a careful comparison and selection process is required to work out the optimal MPFM installation for each specific application. In selecting the optimal multiphase flow metering technology for a specific application, one must first investigate and describe the expected flow regimes from the wells to be measured and determine the production envelope Subsequently one must assess if there exists MPFMs with a corresponding measuring envelope making them suitable for the purpose of measuring the well streams in the specific application The well stream flow rates will vary over the lifetime of the well, and it is important to ensure that the MPFM will measure with the required uncertainty at all times .therefore MPFMs must Be capable of continuously measuring the representative phases and volumes within the required uncertainties.

The reasons behind the necessity of having multiphase flow for metering instead of test separators are:

- Multiphase flow meters help allocate production among working and royalty interest owners or record volumes for custodial transfer at pipeline stations and or port terminal, this is essential for project partners and also for governments, which have testing requirements for accurate computation of taxes and royalty payments. For example, measurements might be made on a given well during a one-week period so the results can be extrapolated to allocate production over a longer time.

- Operating conditions sometimes prevent complete separation of the fluid phases. Some oil remains in the water, some water remains in the oil, some gas remains in the liquids and some liquids in the gas. These conditions cause errors in separator instruments, which are designed to measure streams of single-phase gas, oil or water.
- Test separators have difficulty measuring certain anomalous flow regimes because of the need for stable processing conditions and the fact that response to dynamic flow conditions is always delayed.
- Problematic flow regimes include fluid slugs, in which one phase is interrupted by another phase; foams, which conventional separators cannot handle. A data comparison between multiphase flow meters and separators are shown in figure (22).
- The separators cannot handle the emulsions that require additional heat or chemical treatment to separate the one phase that is suspended in another.
- Viscous fluids such as heavy oil make separation and accurate test measurements extremely difficult.
- The pressure drop across multiphase flow meters is significantly less than for conventional separators, which allows wells to be tested close to actual producing conditions.

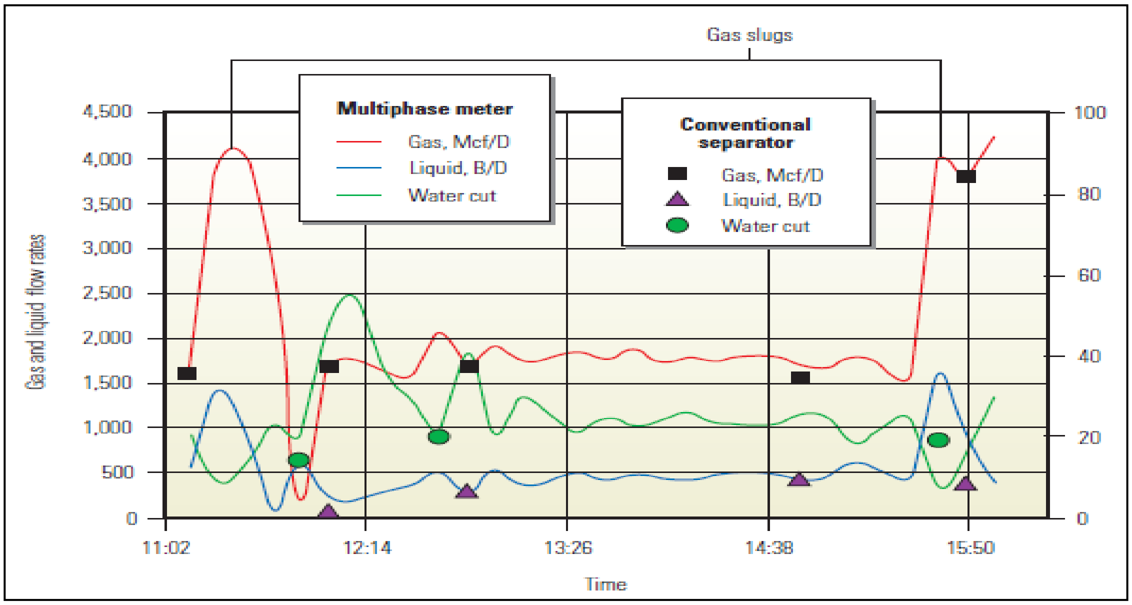

Figure 22 Multi phase and separate data comparison[26]

Mixmeter Multiphase Meter[41]

Mixmeter is a simple, compact, in-line multiphase meter for well test, reservoir management and allocation metering applications. It can be used to replace a test separator or extend the throughput of a test facility. Mixmeter as illustrated in figure (23) is a reliable solution for production measurement providing the information needed to enhance production capability and provide production and reservoir specialists with the data required to understand and optimize well performance without separating a flow stream into individual gas, oil and water phases. Mixmeter is a combination of proven technology, established measurement techniques and simple design, its performance is unaffected by flow regimes or the dominant phase (oil or water) and it requires only minimal configuration and calibration.

Description of the Mixmeter

Mixmeter has no moving parts. It comprises a single spool (less than 900mm in length) containing pressure and temperature sensors, a patented mixer and a dual energy gamma phase fraction instrument. The homogenizer in Mixmeter is also designed to generate a characteristic differential pressure (DP) for bulk measurement, a technique well established for its stability in multiphase flow. The DP provides accurate measurement and has been proven in laboratory and field applications over a wide range of fluids. Phase fractions are measured by a dual energy gamma absorption instrument. Dual energy gamma is used because of its stability in varying process conditions such as dominant phase or fluid properties.

Advantages of Mixmeter

1- The elimination of the velocity differences (slip) which occur between gas and liquid phases (often in excess of 100:1) are critical to multiphase measurement accuracy and a key operating principle of Mixmeter. Whereas Mixmeter is mixing the flow with an innovative homogenizer ensuring that evenly dispersed flow is always present and allowing the use of simple, established techniques for bulk velocity and phase fraction measurement.

2- The turbulent flow caused by the dual vortex effect of the mixer also discourages the formation of scale or wax precipitation in the measurement section.

3- Phase fractions are measured by dual energy gamma absorption instrument. Dual energy gamma is used because of its stability in varying process conditions such as dominant phase or fluid properties

4- Mixmeter field equipment is designed for minimal power consumption Measurement results are displayed in both tabular and graphical formats. All Mixmeter data is stored and can be downloaded for processing off-line in Windows software.

5- Pressure drop in the Mixmeter is a function of velocity and gas void fraction (at actual conditions). Mixmeter is designed to produce a minimal pressure drop.

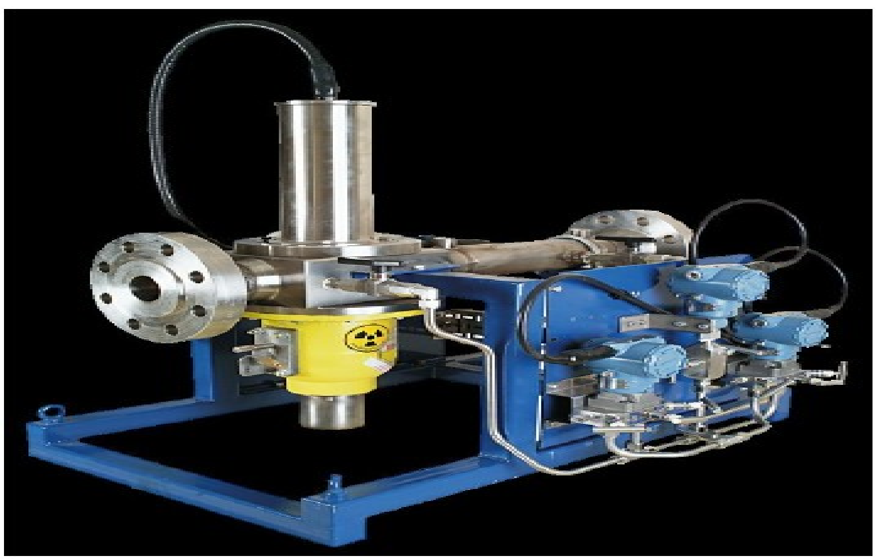

Figure 23 Mixmeter multi phase meter[41]

Comparison of meters (differences)

1. Accuracy and rangeability: (reported as 100:10 Gpm)

2. Repeatability

3. Measuring one property or more
4. One phase or multi-phase flow measurments
5. Mechanisms of measuring (magnetic, pressured differential thermal).

Accuracy vs. Repeatability [8]

In applications where products are sold or purchased on the basis of a meter reading, absolute accuracy is critical. In other applications, repeatability may be more important than absolute accuracy. Therefore, it is advisable to establish separately the accuracy and repeatability requirements of each application and to state both in the specifications. When a flow meter's accuracy is stated in % CS or % FS units, its absolute error will rise as the measured flow rate drops. If meter error is stated in % AR, the error in absolute terms stays the same at high or low flows. Because full scale (FS) is always a larger quantity than the calibrated span (CS), a sensor with a % FS performance will always have a larger error than one with the same % CS specification. Therefore, in order to compare all bids fairly, it is advisable to convert all quoted error statements into the same % AR units. It is also recommended that the user compare installations on the basis of the total error of the loop. For example, the inaccuracy of an orifice plate is stated in % AR, while the error of the associated d/p cell is in % CS or % FS. Similarly, the inaccuracy of a Coriolis meter is the sum of two errors, one given in % AR, and the other as a % FS value. Total inaccuracy is calculated by taking the root of the sum of the squares of the component inaccuracies at the desired flow rates.

In well-prepared flow meter specifications, all accuracy statements are converted into uniform % AR units and these % AR requirements are specified separately for minimum, normal, and maximum flows. All flow meter specifications and bids should clearly state both the accuracy and the repeatability of the meter at minimum, normal, and maximum flows. Table 1 in Appendix 1, provides data on the range of Reynolds numbers (Re or R_D) within which the various flow meter designs can operate. In selecting the right flow meter, one of the first steps is to determine both the minimum and the maximum Reynolds numbers for the application. Maximum R_D is obtained by making the calculation when flow and density are at their maximum and viscosity at its minimum. Conversely, the minimum R_D is obtained by using minimum flow and density and maximum viscosity.

If acceptable metering performance can be obtained from two different flow meter categories and one has no moving parts, select the one without moving parts. Moving parts are a potential source of problems, not only for the obvious reasons of wear, lubrication, and sensitivity to coating, but also because moving parts require clearance spaces that sometimes introduce "slippage" into the flow being measured. Even with well maintained and calibrated meters, this unmeasured flow varies with changes in fluid viscosity and temperature. Changes in temperature also change the internal dimensions of the meter and require compensation. Furthermore, if one can obtain the same performance from both a full flow meter and a point sensor, it is generally advisable to use the flow meter.

Because point sensors do not look at the full flow, they read accurately only if they are inserted to a depth where the flow velocity is the average of the velocity profile across the pipe. Even if this point is carefully determined at the time of calibration, it is not likely to remain unaltered, since velocity profiles change with flow rate, viscosity, temperature, and other factors. If all other considerations are the same, but one design offers less pressure loss, it is advisable to select that design. Part of the reason is that the pressure loss will have to be paid for in higher pump or compressor operating costs over the life of the plant.

Another reason is that a pressure drop is caused by any restriction in the flow path, and wherever a pipe is restricted becomes a potential site for material build-up, plugging, or cavitation. Before specifying a flow meter, it is also advisable to determine whether the flow information will be more useful if presented in mass or volumetric units. When measuring the flow of compressible materials, volumetric flow is not very meaningful unless density (and sometimes also viscosity) is constant. When the velocity (volumetric flow) of incompressible liquids is measured, the presence of suspended bubbles will cause error; therefore, air and gas must be removed before the fluid reaches the meter. In other velocity sensors, pipe lines can cause problems (ultrasonic), or the meter may stop functioning if the Reynolds number is too low (in vortex shedding meters, $R_D > 20,000$ is required). In view of these considerations, mass flow meters, which are insensitive to density, pressure and viscosity variations and are not affected by changes in the Reynolds number, should be kept in mind. Also underutilized in the chemical industry are the various flumes that can measure flow in partially full pipes and can pass large floating or settleable solids.

1.3.5 Water cut measurement meters

Water cut meter measures the water content (cut) of crude oil and hydrocarbons as they flow through a pipeline. While the title "Water cut" has been traditionally used, the current API naming is OWD or On-Line Water Determination. The API and ISO committees as of yet have not come out with an international standard for these devices but there is however a standard in place for fiscal automatic sampling of crude oil namely API 8.2 and ISO 3171.[6] Water cut meters are typically used in the mineral oil industry to measure the water cut of oil flowing from a well, produced oil from a separator, crude oil transfer in pipelines and in loading tankers. There are several technologies used. The main technologies are dielectric measurements using radio or microwave frequency and NIR measurements and less common are nuclear based instruments.[6]

1.3.5.1 Red Eye 2G Water-Cut Meter (Weatherford product) [34]

The *Red Eye* 2G water-cut meters as shown in figure (24) measuring ability easily differentiates oil from water, based on near-infrared spectroscopy. Outperforming its predecessor’s reach with high water-cut levels, the *Red Eye* 2G meter simultaneously measures multiple wavelengths, including both water- and oil-absorbent peaks.

Changing salinity does not affect the measurement because the water absorption is based on the molecule itself, not what is dissolved in the water. Scattering caused by emulsions, sand, or gas bubbles has the same effect at all wavelengths and can be nullified. Because of multiple wavelength measurements the *Red Eye* 2G water-cut meters it has a great tolerance to varying gas conditions.

GVF effects of up to 5% have no effect on unit accuracy and GVF levels up to 20% have only minimal effect. The insertion-style design reduces installation costs, especially for large line size applications. The electronics are mounted directly to the measurement probe, so only the field wiring is required for the power and output signal cables The *Red Eye* 2G water-cut meters comes in standard, 302°F (150°C) maximum process temperature.

Figure 24 Red Eye 2G Water-Cut Meter[34]

Typical applications

1- Well testing
2- Individual well monitoring
3- Group production at centralized facilities
4- Dewatering monitoring systems for crude oil tanks

1.3.5.2 Red Eye Multiphase water-cut Meter

The Red Eye multiphase water-cut meter extends the unparalleled performance of Weatherford's original Red Eye 2G water-cut meters to a full range of gas volume fractions (GVF). This meter Designed to work in full three-phase flow (oil, water and gas). Multiphase meter measures relative water and oil concentrations in streams with up to 99.5% GVF. At GVF levels above 99.5% this meter can be used for water onset detection. Using strong water absorption wavelengths in the near infrared (NIR), the multiphase meter can clearly detect water at or below 0.25 BBL/MMSCF.

The meter also has the ability to differentiate methanol or similar alcohol based hydrate inhibitors. By measuring five key wavelengths in the NIR spectrum, the Red Eye multiphase water-cut meter can distinguish four components (gas, water, methanol and condensate) in three phases (gas, liquid hydrocarbon and aqueous). The meter is available for line sizes from 2 to 24 in.

Typical applications

The Red Eye multiphase water-cut meter is designed to work with vastly different types of flow like continuous liquid and gas flow streams and can be used for the following applications

- Individual well production monitoring
- Water onset detection
- Undersized test separators
- Optimized injection
- of hydrate inhibitors

1.3.5.3 Red Eye Hot Tap Insertion and Retraction Technology[35]

Red Eye hot tap as shown in figure (25) Insertion and retraction technology allows insertion and retraction of a water-cut meter in a flowing pipeline. The meter uses patented optical sensor technology to accurately measure the full range of water cut (0 to 100%) in a commingled oil and water stream. Very high accuracy across all water-cut levels and easy installation and configuration make this unique meter suitable for numerous applications. The meter can be used in standalone mode to measure and report instantaneous water cut and in conjunction with the net oil computer (NOC) to perform timed production well tests, or as part of the *Red Eye* multiphase metering system (REMMS). The meter is designed for 6-to 12-in. (15.24-to 30.48 cm) piping that has an installed, 2-in. (5.08-cm) ball valve with a 600-lb (272.15 kg) flange ANSI certified for up to 1480 psi (102.7 bar). The distance between the top flange of the ball valve and the top of the piping must be approximately 16.25 in. (41.28 cm).

Figure 25 Red Eye Multiphase Water-Cut Meter[35]

Low cut loop powered easz-1 as shown in figure (26) online water cut meter, is quick ship and reliable online instrument for the online determination of S & W in hydrocarbon streams using the latest developments in electronic design for low-powered and reliable online measurements of water in oil. For high cut the high cut easz-1 is used for measuring the water content as shown in figure (27).

Features

- Adjustable ranges 0-25%
- Flexible sizes 2" to 42"
- Temperature compensated

- 2 wire intrinsically safe
- Available in screwed or flanged connections
- ASTM 316SS design as standard
- Response time 1 second
- Standard temperature limit 125°C (higher temperature on request

Figure 26 Low cut loop powered easz-1[35]

High cut EASZ-1

Although several manufacturers may recommend that upstream mixing is necessary to achieve best results when measuring high contents of water in oil, it is not always the practice to supply mixers together with the monitoring instrument. To achieve meaningful results in high cut measurement EESIFLO combines its in-house static mixers and water-cut monitors shipped in a single piece spool ready for installation on high cut applications. Sample ports can be added as an option for applications requiring further instrumentation.

Features

- 0 - 100% output
- Homogenous mixture for increased accuracy
- Available in sizes 2" to 48" bore
- Loop powered EExia 11B T4 ATEX IECEX and CSA (FM) approved
- Easy installation and operation
- Low and high pressure versions

Figure 27 High cut loop powered easz-1[35]

1.3.6 Temperature and pressure measurement

Usually pressure and temperature continuous recording display at the oil field on the top of the well. The continuous measurement of the temperature measurement is very important as the both conditions have an impact on the production process and on the equipment and no doubt on the site safety.

1.3.6.1 Pressure measurement

There are many kinds of pressure measurements and different shapes and different applications, for instance, pressure gauges which are gauges placed above the master gate valve before the wing valve. The following table (3) is representing a comparison between the other models of the pressure gauge:

Table 3 comparison of pressure gauges[27]

Name	Features and application	picture
Bourdon tube pressure gauge, stainless steel series,NS 40, 50, 63	• Large, easy-to-read scale due to nominal size 250 • Long service life, robust • Scale ranges up to 0 … 1000 bar. **application** • For gaseous and liquid media that are not highly viscous or crystallizing • For aggressive media	
Bourdon tube pressure gauge model 132.28, Stainless-Steel System	• Vibration and shock resistant • Measuring system stainless steel, also for aggressive media • Especially sturdy design • Stainless steel case • Scale ranges up to 0 … 40 bar **Application** • For gaseous and	

	liquid media that are not highly viscous or crystallizing	
Bourdon tube pressure gauge, stainless steel series, NS 40, 50, 63	**Application** • Suitable for gaseous, liquid and corrosive media, also in a corrosive environment, for demanding high purity applications • Suitable for all HP (High Purity) applications • Gas distribution system	
UHP flow-through-gauge, model 432.25.2" (FTG)	**Applications** • Suitable for gaseous, liquid and corrosive media, also in a corrosive environment, for demanding high purity applications. • Semiconductor and flat panel industry • Gas distribution systems • Medical gases • Hook-up-application	

Optibar -P 3050 C	**Applications** • Temperature range from –45 °C to 85 °C Hook-up-application	
Christmas Tree Gauges, Type 1020S, ASME B 40.1	**Applications** • Pressure ranges 1000/20,000 PSI. • Stainless	

Diaphragm seals and Close coupling[36]

This product are associated with pressure gauges due to With aggressive media, high temperature, dirty, polymerizing or toxic products the diaphragm seals technique is used. Via capillaries which are filled with oil, designed for the application, the pressure is transferred from the product-contacted side to the transmitter. As an example for the Diaphragm seals figure (28) where used to overcome the problems associated with traditional instrument, manifold installations that are connected with impulse lines. Traditional remote mounted instrument, manifold installations with impulse lines were used in the past to allow technician’s access to instruments that required regular calibration and continuous maintenance.

Figure 28 Schneider Close Couplings as a diaphragm seals[36]

Temperature measurement:

Temperature should be most accurately measured by contact method .Petroleum engineers need to know flowing well head temperatures (FWHT) in order to determine choke sizes and line heater capacities. It is also necessary to know WHT in order to calculate gas flow rates through orifice meters and for converting well-head pressures to bottom-hole pressures. However, in spite of the importance of obtaining WHT's, it is very difficult to obtain accurate measurements in the real world of oil and gas production.

1. **Local temperature measuring device**

   Thermometer devices used to measure the temperature of the petroleum fluids as shown in the figure (29).

Figure 29 Thermometer device

2. Down hole fiber optic sensor

A fiber optic sensor as shown in figure (30) is a sensor that uses optical fiber either as the sensing element ("intrinsic sensors"), or as a means of relaying signals from a remote sensor to the electronics that process the signals (extrinsic sensors).Optical fibers can be used as sensors to measure strain, temperature, pressure and other quantities by modifying a fiber so that the quantity to be measured modulates the intensity, phase, polarization, wavelength or transit time of light in the fiber. Sensors that vary the intensity of light are the simplest, since only a simple source and detector are required. Fibers have many uses in remote sensing. Depending on the application, fiber may be used because of its small size, or the fact that no electrical power is needed at the remote location, or because many sensors can be multiplexed along the length of a fiber by using different wavelengths of light for each sensor, or by sensing the time delay as light passes along the fiber through each sensor. Time delay can be determined using a device such as an optical time-domain reflect meter.

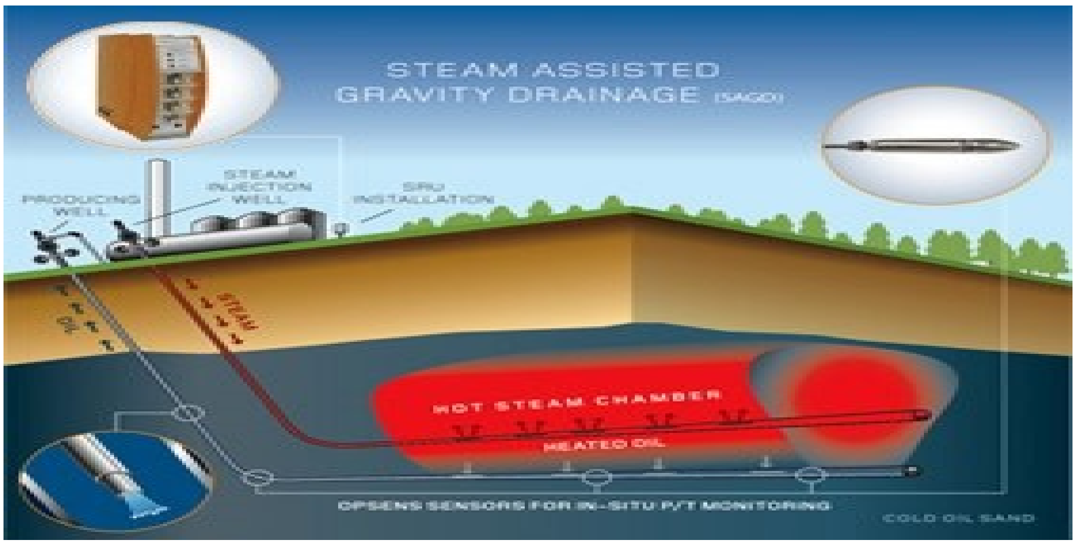

Figure 30 Fiber glass sensor

1.3.7 Emissions wastes

Production operation includes normal well operations, separations and treating at production facilities and gas plants, and walkovers. Typical wastes generated within these areas are expected. Production facilities gather produced vapors, fluids, and solids from wells, separate liquid hydrocarbons and natural gas, and prepare them for sale. Salable products generally have restrictions as to allowable contaminants. In the case of oil, a maximum limit is set on basic sediment and water (BS&W), typically 0.5 to 1.0%. [10]in general, fugitive emissions from oil and gas activities may be attributed to the following primary types of sources:

1- Fugitive equipment leaks
2- Process venting
3- Evaporation losses
4- Disposal of waste gas streams (e.g., by venting or flaring)
5- Accidents and equipment failure

Accidents and equipment failures may include well blowouts, pipe line breaks, tankers accidents, tank explosions, gas migration to the surface around the outside of wells, and surface-casing vent blows. Gas migration to the surface may be caused by a leak in the production string at some point below the surface casing, or by the migration of material from one or more of the hydrocarbon-bearing zones which are penetrated (e.g., a coal seam). A surface-casing vent blow may be caused by a leak from the production casing into the surface casing or by fluid migration up into the surface casing from below. While methane (CH_4) is the predominant type of greenhouse gas emitted as a fugitive emission in the oil and gas sector, noteworthy fugitive emissions of carbon dioxide (CO_2) and, to a much lesser extent, nitrous oxide (N_2O), may also occur. CO_2 is present as a natural constituent of most untreated hydrocarbon streams and occurs in high concentrations in some enhanced oil recovery schemes (i.e., where CO_2 and fireflood schemes are used).Consequently, it is a constituent of all fugitive emissions, plus noteworthy amounts of raw CO_2 are stripped from the produced gas at sour-gas processing and ethane extraction plants, and are subsequently discharged to the atmosphere through vents or flare.

Chapter 2

2.Petroleum field processing and measured properties-natural gas

2.1 Introduction

Natural gas is playing a growing energy role. The scale of its reserves and its environmental advantages favor its use. Additionally, natural gas reserves have grown rapidly in recent years. This chapter gives explanation of the major natural gas process as shown in figure (31) starting from the well into the market. Additionally, the chapter is highlighting the obstacles that measurements face and instruments are presented. Furthermore, a discription of the measurments devices is given. Natural gas measurement is the basis of commerce between producers, royalty owners, transporters, process plants, marketers, state and federal government authorities. it is essential that material quantity measurements be precise and accurate with minimal bias errors because Inaccurate measurement may result in loss of customers, adverse publicity, potential penalties, and legal liabilities.

Natural gas production loop

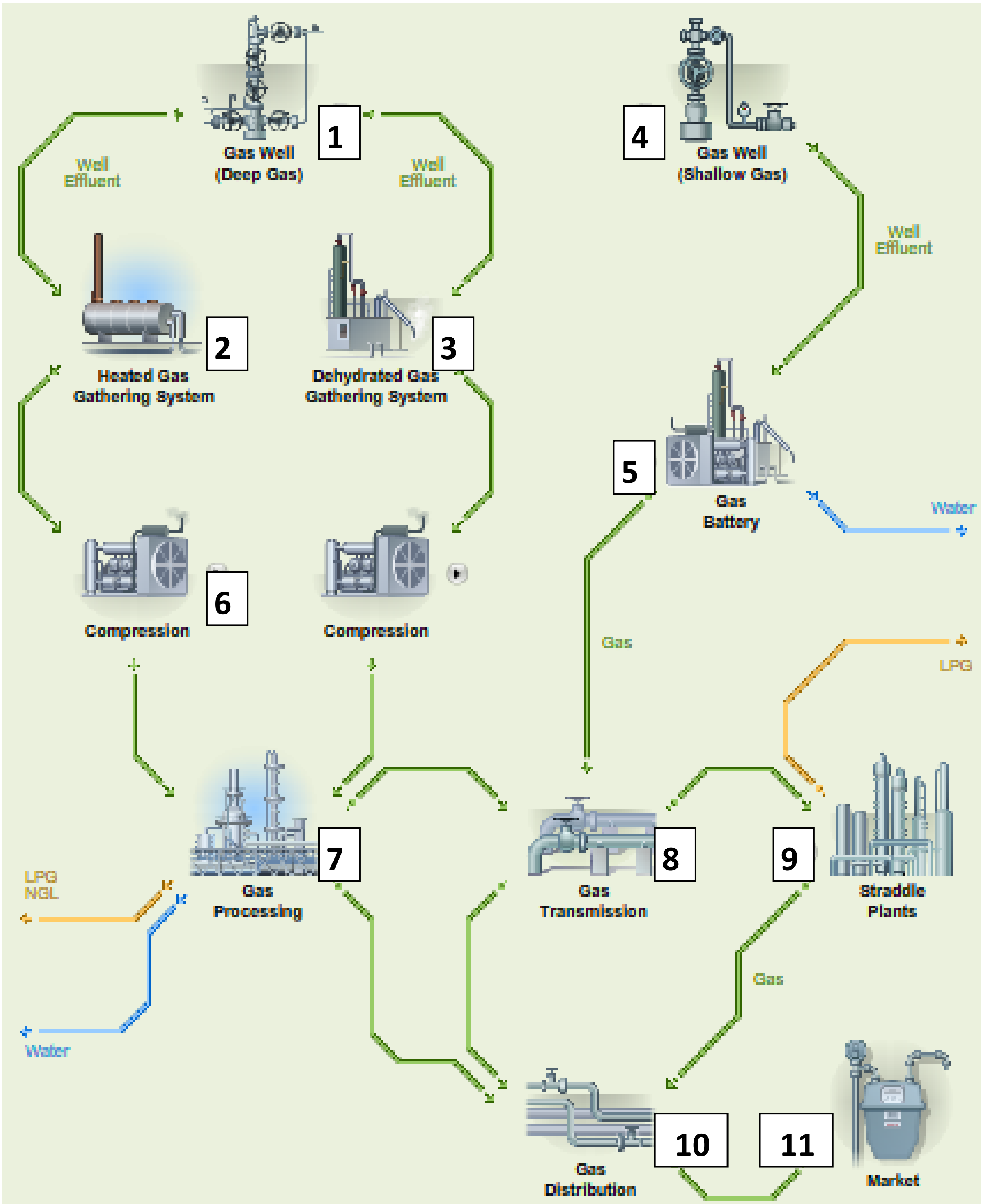

Figure 31 Natural gas production cycle[2]

Definitions of all the processes in figure (31):

1-Gas Well : Any well which produces natural gas not associated or blended with crude petroleum oil at the time of production, or produces more than 100,000 cubic feet of natural gas for each barrel of crude petroleum oil from the same producing horizon.

2-Natural Gas Gathering System: A facility as shown in figure (32)consisting of gas lines used to move products from individual wells to booster compressor stations and one gathering station to another or a processing plant or transmission pipeline. The facility may also include gas dehydrators, line heaters, and pigging facilities.

3-Heated Gas Gathering System: A facility as shown in figure (33)consisting of gas lines used to move products from individual wells to booster compressor stations and one gathering station to another or a processing plant or transmission pipeline. The facility may also include gas dehydrators, line heaters, and pigging facilities.

4-Gas Well: Any well which produces natural gas not associated or blended with crude petroleum oil at the time of production, or produces more than 100,000 cubic feet of natural gas for each barrel of crude petroleum oil from the same producing horizon.

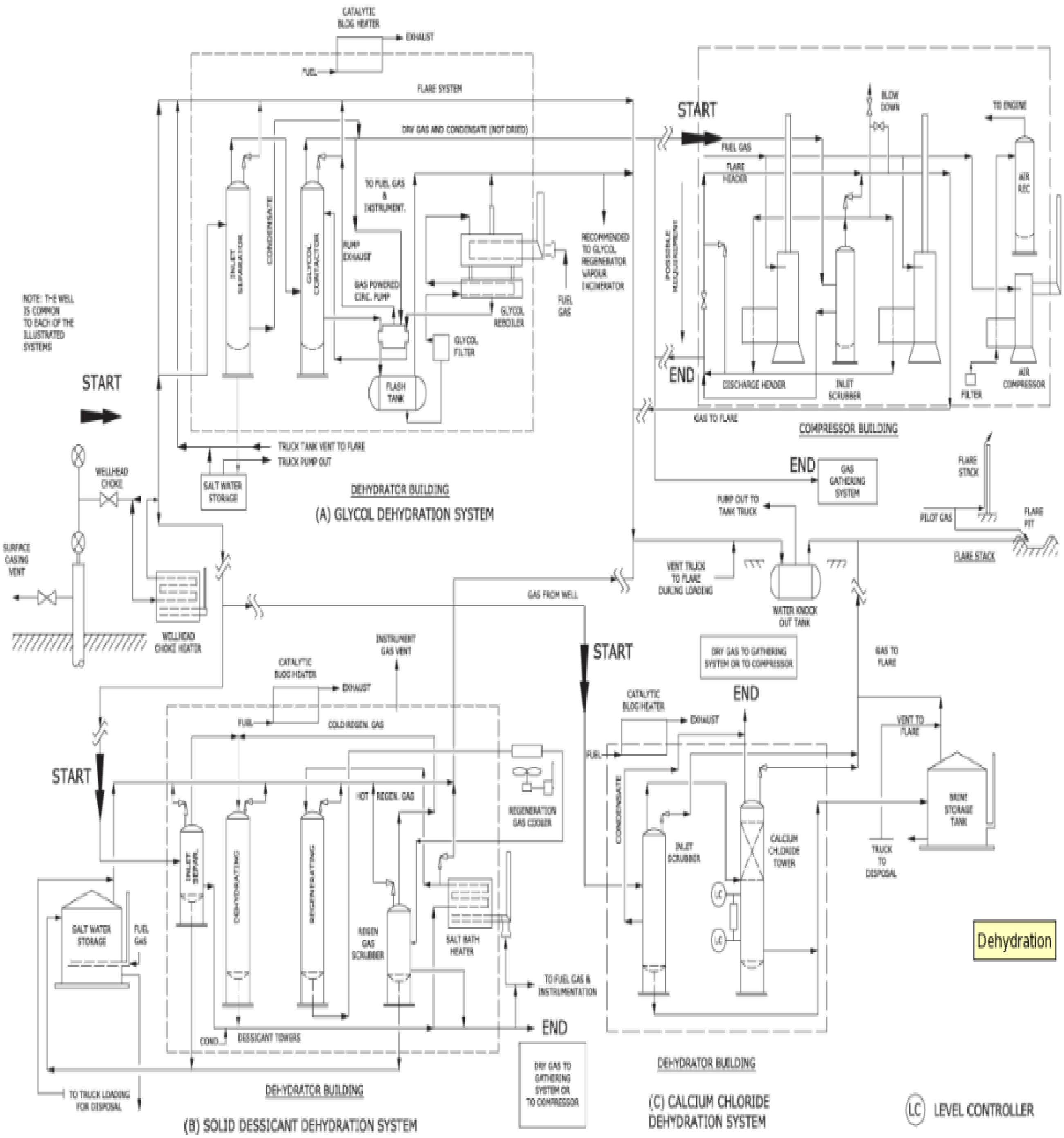

Figure 32 Dehydration gas gathering system²

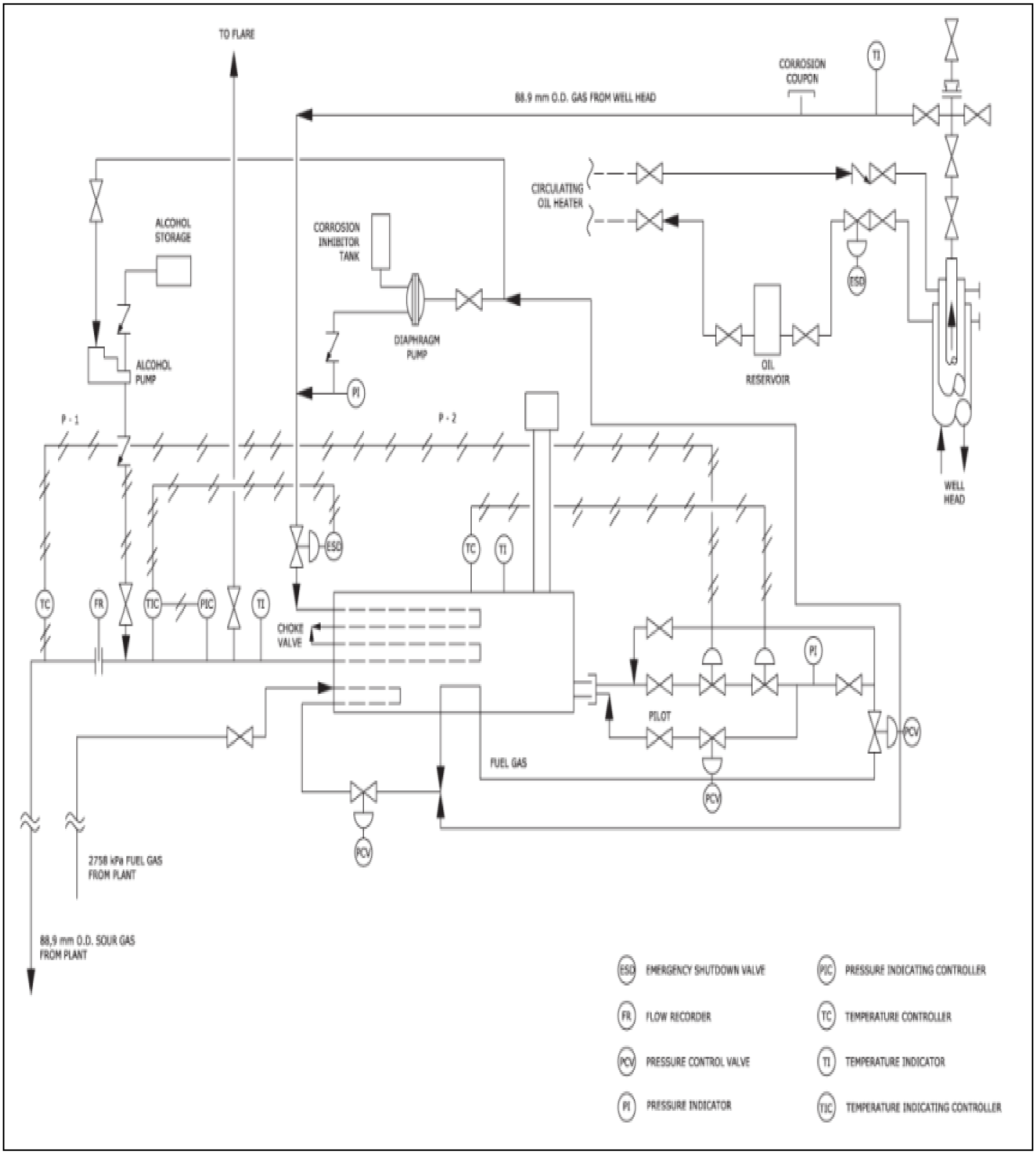

Figure 33 Natural gas heated system diagram[2]

5-Natural Gas Battery: A system or arrangement of surface equipment as shown in Figure (34) that receives primarily gas from one or more wells prior to delivery to a gas gathering system, to market, or to other disposition. Gas batteries may include equipment for measurement and for separating inlet streams into gas, hydrocarbon liquid, and/or water phases. There are many occurrences of gas battery codes being a proration hub. In these instances there is no equipment onsite except a meter.

6-Compressor Station: Service equipment intended to increase the flowing pressure of the gas that it receives from a well, battery, gathering system or transmission pipeline for delivery of natural gas to processing, storage or markets.

7-Natural Gas Processing Plant: Natural gas processing facility for

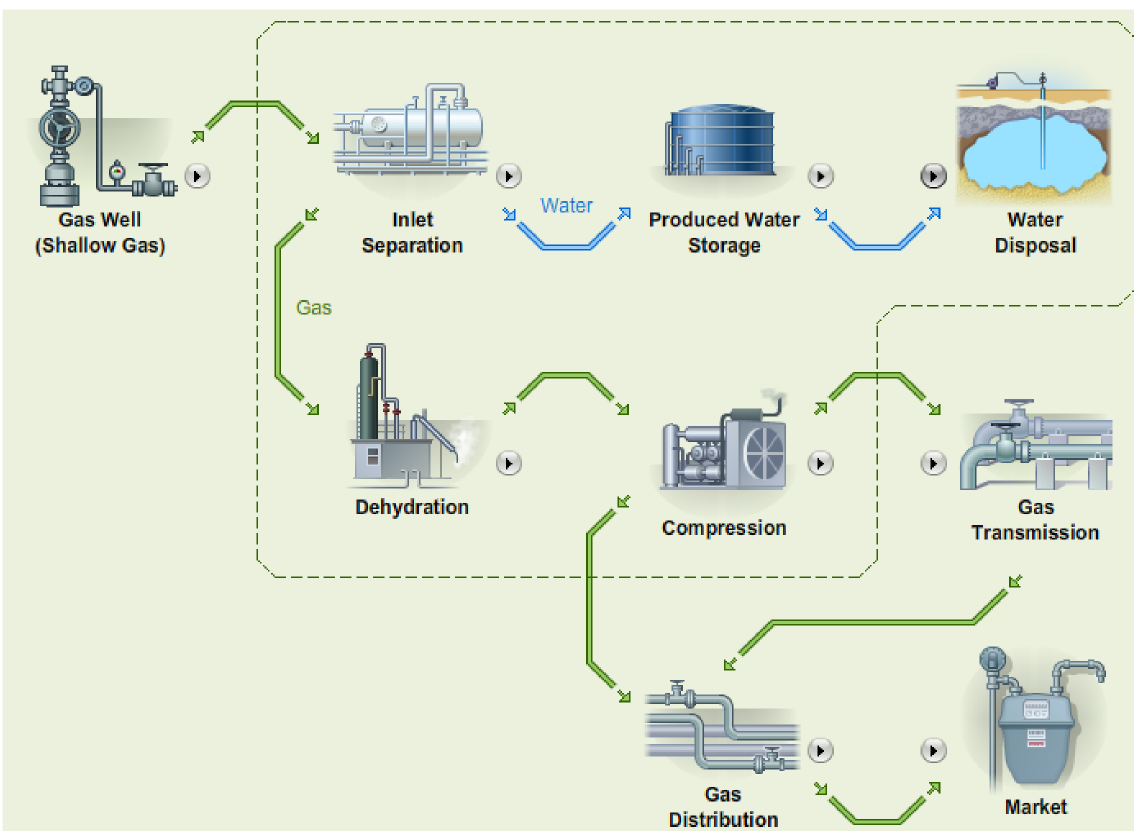

Figure 34 Gas batteries Loop[2]

extracting from natural gas; helium, nitrogen, ethane, or natural gas liquids, and/or the fractionation of mixed NGL to natural gas products. A natural gas processing plant may also include natural gas purification processes for upgrading the quality of the natural gas to be marketed to meet contract specifications (i.e., for removing contaminants such as water, H2S, CO2, and possibly adjusting the heating value by the addition or removal of nitrogen). The inlet natural gas may or may not have been processed through lease separators and field facilities.

8-Gas Transmission: The transport (usually by cross-country pipelines) of natural gas at high pressure from producing areas to consuming areas.

9-Gas Plant – Straddle: A gas processing plant located on or in connection with a natural gas transmission line that removes residual natural gas liquids from the gas and returns the residue gas meeting commercial gas specifications to the transmission pipeline.

10-Gas Distribution: The delivery of natural gas from high-pressure transmission systems to customers.

11-Gas Market: Total end-user (i.e., industrial, commercial and residential) natural gas demand.

2.2 Measured natural gas properties – production stage

2.2.1 Gas viscosity

Opposite to oil viscosity that can be measured using of the apparatus as mentioned in chapter 1, the gas viscosity can be calculated using the equation shown below based on the gas composition information. The composition information is measured in the lab using Gas chromatograph instrument. The knowledge of the gas viscosity and condensates is necessary to perform flow calculations in the different stages of production, and particularly to determine pressure drops.

The gas viscosity at elevated pressure and temperature is usually estimated using the charts by Carr-Kobayashi-Burrows /1954/. Dempsey /1965/ expressed their chart or the following equations from (3) to (6).

$$\begin{aligned}\ln\left[T_{pr}\left(\frac{\mu_g}{\mu_1}\right)\right] &= a_0 + a_1\,p_{pr} + a_2\,p_{pr}^2 + a_3\,p_{pr}^3 \\ &+ T_{pr}\left(a_4 + a_5\,p_{pr} + a_6\,p_{pr}^2 + a_7\,p_{pr}^3\right) \\ &+ T_{pr}^2\left(a_8 + a_9\,p_{pr} + a_{10}\,p_{pr}^2 + a_{11}\,p_{pr}^3\right) \\ &+ T_{pr}^3\left(a_{12} + a_{13}\,p_{pr} + a_{14}\,p_{pr}^2 + a_{15}\,p_{pr}^3\right)\end{aligned} \qquad (3)$$

Where T_{pr} : pseudo-reduced temperature of the gas mixture
p_{pr} : pseudo-reduced pressure of the gas mixture
a_0-a_{15} : coefficients of the equations are given below

a_0	=	- 2.46211820	a_8	=	- 7.93385684 (10^{-1})
a_1	=	2.97054714	a_9	=	1.39643306
a_2	=	- 2.86264054 (10^{-1})	a_{10}	=	- 1.49144925 (10^{-1})
a_3	=	8.05420522 (10^{-3})	a_{11}	=	4.41015512 (10^{-3})
a_4	=	2.80860949	a_{12}	=	8.39387178 (10^{-2})
a_5	=	- 3.49803305	a_{13}	=	- 1.86408848 (10^{-1})
a_6	=	3.60373020 (10^{-1})	a_{14}	=	2.03367881 (10^{-2})

a_7 = - 1.044324 (10^{-2}) a_{15} = - 6.09579263 (10^{-4})

Standing (1977) proposed a convenient correlation for calculating the viscosity of the natural gas at atmospheric pressure and reservoir temperature

$$\mu_1 = \left(3.0764 \cdot 10^{-5} - 3.712 \cdot 10^{-6} \gamma_g\right)\left(T - 256\right) + 8.188 \cdot 10^{-3} - 6.15\ 10^{-3} \log_{10} \gamma_g \quad (4)$$

The pressure of non-hydrocarbon gases affects the viscosity. This can be corrected for as follows.

$$\Delta\mu_{N_2} = y_{N_2}\left[8.48\left(10^{-3}\right)\log_{10}\left(\gamma_g\right) + 9.59\left(10^{-3}\right)\right] \quad (5)$$

$$\Delta\mu_{CO_2} = y_{CO_2}\left[9.08\left(10^{-3}\right)\log_{10}\left(\gamma_g\right) + 6.24\left(10^{-3}\right)\right] \quad (6)$$

Where μ1= viscosity of the gas at atmospheric pressure and reservoir temperature, cp.

T=reservoir temperature, K.

γ**g**= gas gravity.

y_{N2}, y_{CO2}= Mole fraction of N2, CO2 respectively.

2.2.2 Density measurments

2.2.2.1 Gas Density Transducer

The 7812 gas density Transducer technology illustrated in figure (35) is unique in providing on-line as shown in figure (36), continuous density measurements. The 7812 is based on a resonating cylinder.

The density of the gas flowing through the transducer changes the natural resonant frequency of the cylinder. By maintaining this vibration and measuring its frequency electronically, the density of the gas (which is directly related to mass flow) can be determined. It offers highest accuracy and resolution available today and fast reaction to process changes, Fast reaction to process changes, low maintenance requirement and approved for custody transfer.

Figure 35 Gas Density transducer- 7812 [14]

Specification of the 7812 Gas Density Transducer

1- Density range 1-400kg /m3 (0.06-25lb/ft3).
2- Limits of error (10 to 100%), for nitrogen ±0.1% of reading, for natural gas, ethylene ±0.15% of reading.
3- Maximum operating pressure 250 bar, 3625 psi.
4- Temperature range -20 to +85°C (-4 to +185°F).

5- Process gas must be dry and compatible with Ni-spanC902, Stainless Steel AISI 316, Stycast Catalyst 11 and Permendur Iron.

Applications of the 7812 gas density transducer include

- Gas blending.
- Direct measurement of ethylene density.

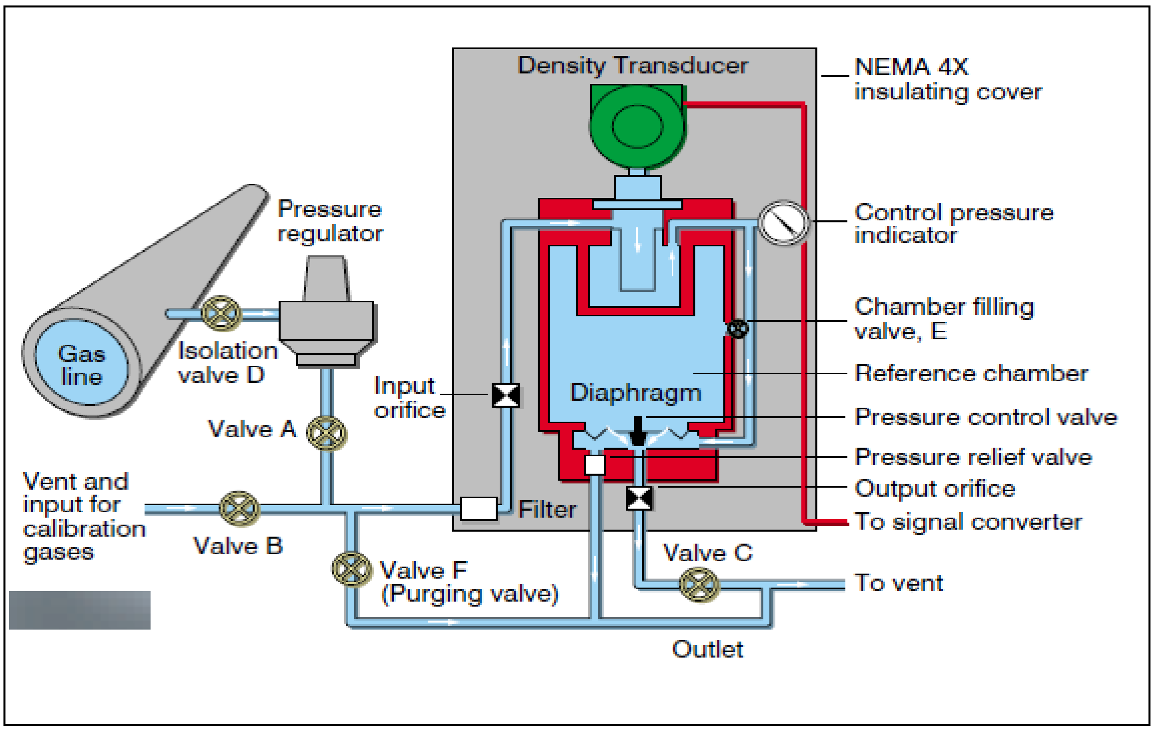

Figure 36 Measurement arrangements for gas density transducer [14]

2.2.2.2 In-flow Gas Density meter DC-60[37]

The In-flow Gas Density Meter DC-60 as shown in figure (37) is used in petroleum industry to measure the gas density and Temperature of natural gas in the flow. High-accuracy, density data for natural gas mixtures are required in entire range of pressure, temperature and compositions encountered in custody transfer.

Figure 37 In-flow Gas Density meter DC-60 [37]

Specification of the in-flow Gas Density Meter DC-60

- Operating principle Resonant frequency vibration
- Density range 0 - 400 kg/m3
- Temperature range -40°C to + 85°C

2.2.3 Gas Specific Gravity

There are different kinds of Transducer that used in the petroleum industry to measure the natural gas specific gravity. 3098 Gas Specific Gravity Transducer as shown in figure (38) is the latest development in a product line well established as the industry standard for gas gravitometers. It is the only product that offers continuous on-line measurements as well as highest accuracy and resolution, fast, dynamic response to process conditions, Custody transfer approval and Self compensation for gas compressibility.

2.2.3.1 Gas specific gravity transducer 3098

Specification

- Density accuracy Up to +0.1% or reading.
- Specific gravity range 0.1 to 3 (typical).
- Repeatability +0.02% of reading
- Temperature range -30 to +50ºC (-22 to +122ºF) or as limited by the dew point of the gas.
- Maximum reference pressure Up to a maximum of 7 Bar absolute .
- Gas flow rate 0.2 to 60 normal cc/s.

Figure 38 Gas Specific Gravity Transducer Source- 3098 [13]

2.2.4 Gas Flow rate measurments

The majority of all gas measurement used in the world today is performed by two basic types of meters, positive displacement and inferential meters. Positive displacement equipment, consisting mainly of diaphragm and rotary style devices, generally account for lower volume measurements. Orifice, ultrasonic and turbine meters are the three main inferential class meters used for large volume measurement today[6]. Table (2-a) in the appendix give the characteristics of the gas flow Meters. The natural gas that is produced is measured before leaving the well location after treatment as shown in figure (39). Customary industry standard measured the produced gas through a check meter. Calculation of total gas flow is done on a monthly basis, usually by a third party gas measurement contractor. These calculations are passed along to the operator who enters the natural gas measurements into their revenue accounting system, the software through which royalty owners are paid.[1]Measurement of gas flow is an important issue for both, within a company and in trade with other companies or consumers. This implies that we have different recommendations on accuracy dependant on the field of use. Intra company measurements are preliminary done for economical reasons and require lower accuracy, but even here accurate measurement at low cost is desirable. In the field, the operator wants accurate measurement of production from each well to help analyze well performance. Volumes transferred to and from storage must also be measured to detect loss. For trade between companies or in case of selling gas to the consumer, measurement devices with higher accuracy have to be used. Today's trends to liberalization of gas markets require more than ever before highly sophisticated measurement systems and well defined standards to enable a fair trade system.

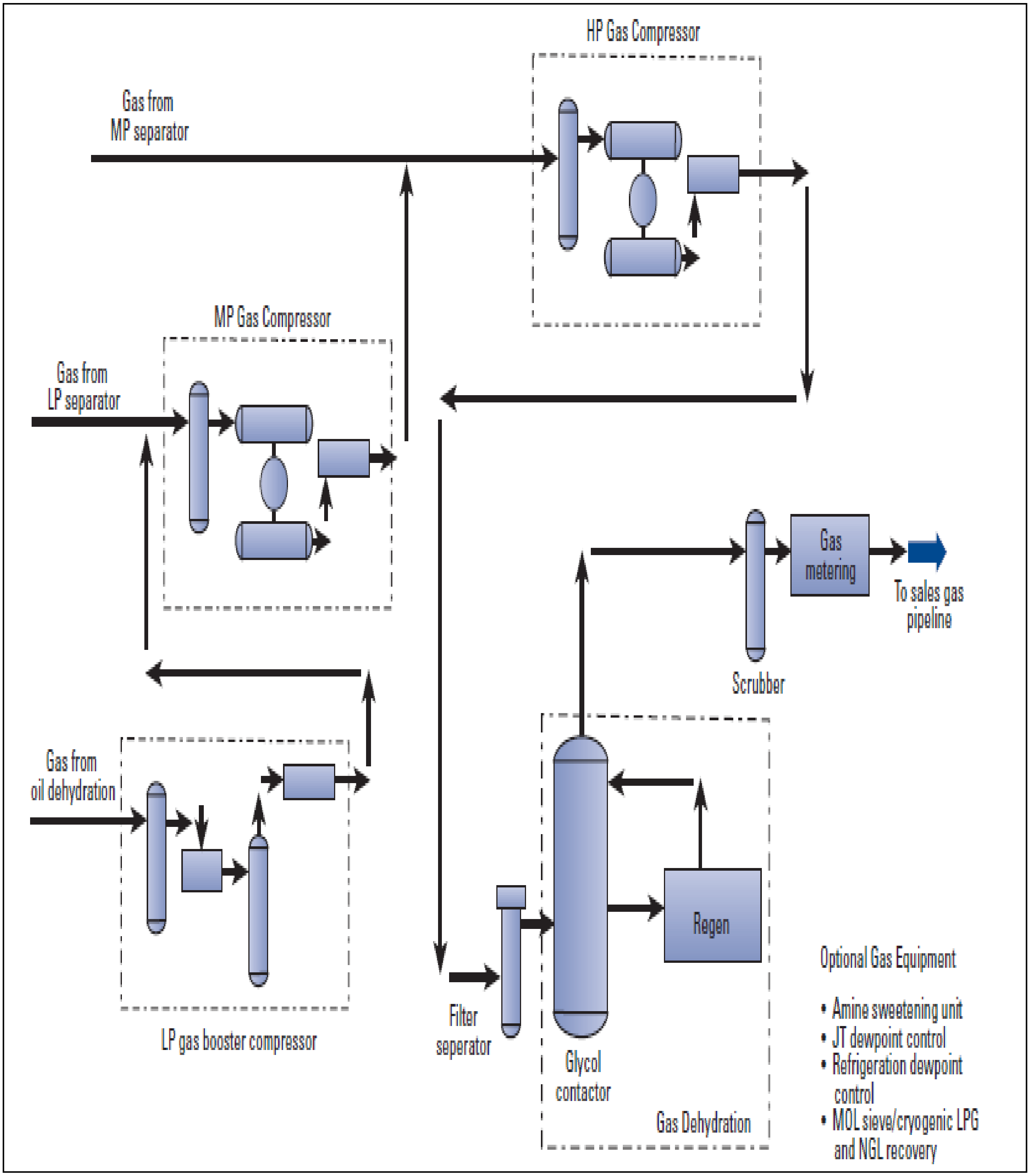

Figure 39 Gas metering position after treatment²

To define the value of gas we need more than volume or mass combined with density. Contracts for trade of natural gas often contain the value BTU (British Thermal Units) per volume to define the heat or energy content of a gas Lower heat content expressed in e.g. BTU per standard cubic feet (scf) results in less energy transferred. Traditionally, gas purchase contracts specify only a minimum BTU content, typically 1000 BTU/SCF. First the most important measurement principles for gas flow measurement are explained in terms of measuring principle and calculation of flow rates. Two physical parameters are measured in flow measurement

- Volume (Nearly all common meters measure this variable)
- Mass (Here only the Coriolis meter and as a recent development thermal methods measure this mass variable).

2.2.3.1 Differential pressure meters (Inferential Rate Meters)

Differential pressure meters use the pressure drop caused by a flow restriction to evaluate the flowing volumes. For different geometries, different corrections have to be applied to get more or less accurate measurements.

Orifice meters

The majority of producing wells measure natural gas production with an orifice style meter. The flow of both gases and liquids can be measured with orifice meters; they are especially popular for natural gases measurement. Orifice meters have no moving parts and are easily serviced in the field.

Differential pressure is measured and recorded as gas passes across an orifice plate, creating a pressure drop allowing for a calculation of the volume of gas passing through the pipe.

Typically, there will be two meters on the well, one owned by the well Operator, and one owned by the First Purchaser[11]. These serve as a "check" for each other – a benefit from the royalty owner's perspective. One of the main types in the petroleum industry is Orifice meters used for measure large volume of gas as the pressure drop occurring at a restriction indicates the flow rate in pipelines The differential pressure method of measuring at orifices is widespread. Differential pressure device that produces a flow rate that is proportional to the square root of the pressure drop across the orifice. A transducer, transmitter, recorder converts the differential pressure into an indication of flow rate.

One of the most versatile and widely used measuring devices is the orifice meter. This instrument has been used for many years in oil and gas operations around the world. An orifice meter is part of a meter station that includes the meter tube, a length of pipe upstream and downstream of the orifice; the orifice plate, which is installed vertically in the meter run; flanges on each side of the orifice plate that are tapped so that pressure can be monitored and a recorder as illustrated in figure (40). Flow rate is inferred from the pressure difference measured by pressure taps upstream and downstream of the plate. And observed pressure drop depends on the taps location. For example for the Flange tap has the highest pressure differential. But for the pipe taps the pressure drop equal to the net pressure.

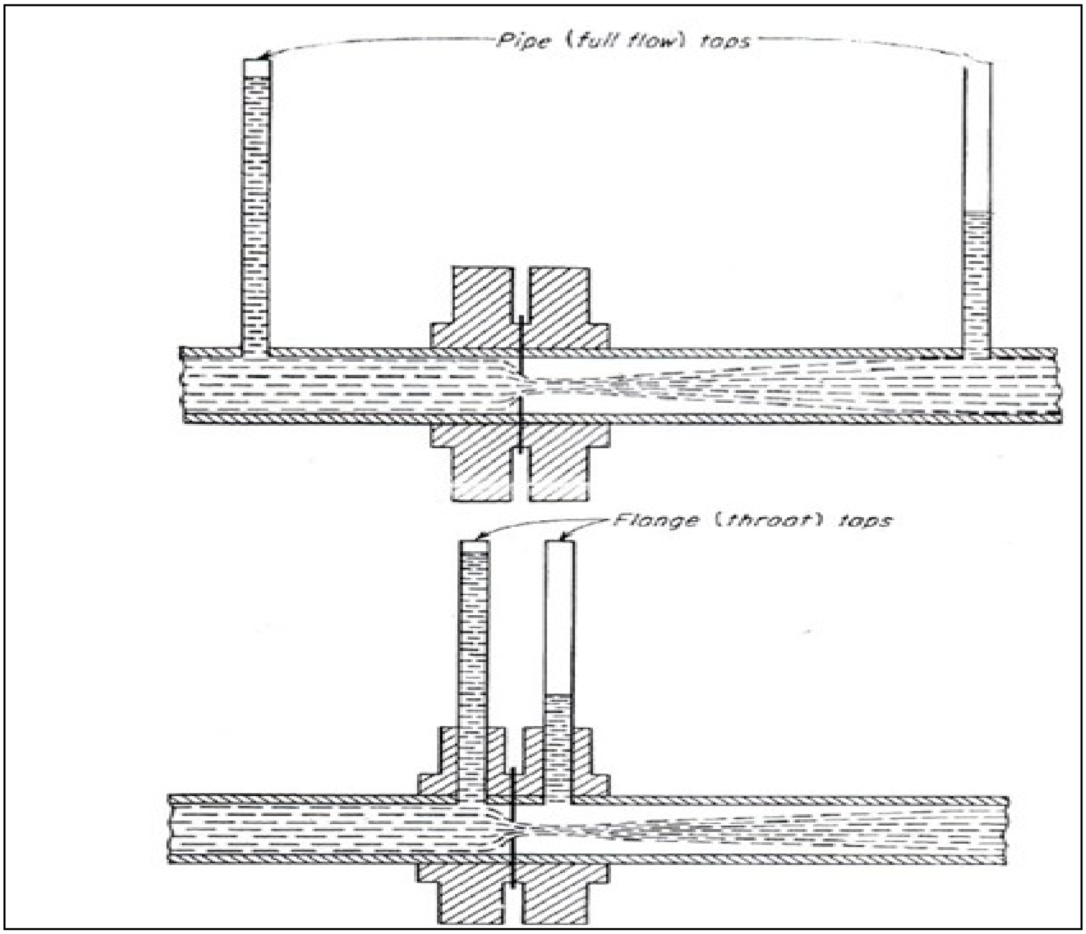

Figure 40 Pipe and flange taps of the orifice meter[12]

Flange taps **$0.15 < \beta < 0.70$**

Pipe taps **$0.20 < \beta < 0.67$**

Where the β ratio= is a ratio of Orifice (d) to meter diameter.

There are different types of Orifice meters as shown in figure (41) including the following

- Concentric Orifice: The concentric orifice is the most common orifice type. It is used especially for gases and water.

- Eccentric Orifice: It is especially employed for measuring liquids containing solids.
- Segmental Orifice: It posses the same basic applicability as the Eccentric Orifice with an additional advantage, that a Segmental Orifice does not dam solids on the upstream side of the orifice plate. Accuracy of the orifice meter is ±0.5 - 1%

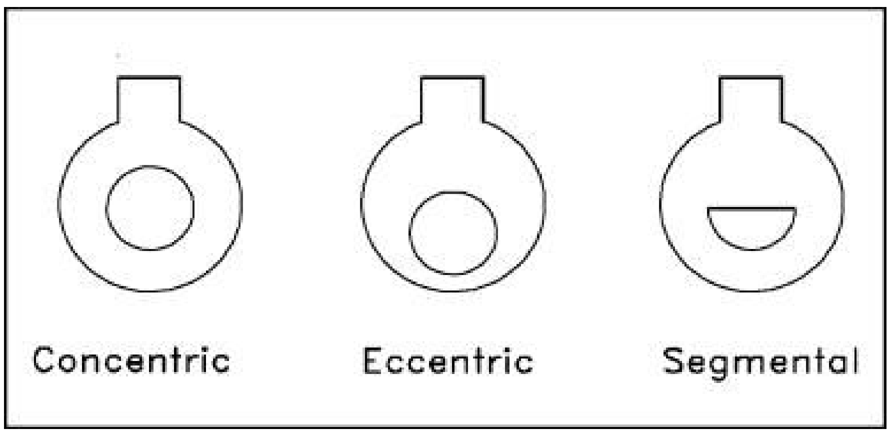

Figure 41 Orifice meter types[38]

Conditions Affecting Accuracy

Various conditions can exist in the field that adversely affects the measuring accuracy of an orifice metering system. Any discussion of accurate flow measurement should contain a portion on what kind of results can be obtained if all precautions are taken. Without full qualification of the source of the data these numbers are meaningless. However, for some general ranges of experienced balances of measured flow inputs versus flow outputs, the large diameter high pressure pipe lines run a few tenths of a percent lost or unaccounted for. In production fields, where some of the described problems are more prevalent, the balance may be several percent at best. However, experience tells us that the only way these balances are obtained is by following all of the best practices of design, application, installation, maintenance and interpretation.

For most accurate measurement, the orifice meter should be applied to gas flows, which are steady or very slowly with time, in the turbulent flow region and well below sonic velocity. The gas should be single phase and not contain suspended particles. If the gas temperature is above or below the ambient Temperature consideration may be given to insulating the upstream and downstream tubes and the lead lines to the recording devices or transducers. If flow changes are large (such as over 5 to 1 turn down) and slow with time (such as seasonal load changes) provision should be made to change orifices to provide a good differential at all rates.

Availability of sufficient permanent pressure loss is a requirement for any head-measuring device and must be considered in its application. The coefficient of discharge of an orifice is determined empirically so that the particular orifice meter being installed must reproduce as closely as possible the installation on which the tests were run whether they are specific tests on the unit itself or general tests run by the various standards agencies. These agencies have detailed requirements of installation that have been determined while running a number of calibrations over the years. In each case deviation from the test installations may introduce errors so that a complete understanding of these requirements is necessary before changes from these standards are made.

The readout equipment on the differential across the orifice and the other variables such as density, pressure, temperature, specific gravity, composition, heating value (depending on the method of measurement and quantity units required) must be properly installed, operated, to obtain accurate gas flow measurement. This is also true of the taps to the flowing stream and the sample lines running to each piece of equipment. Proper calculation from the measured variables is required and depending on the flowing characteristics. One system of readout may be advantageous to another with this introduction; examples will show the kind of problems that can exist if the above precautions are not taken. There have been many papers and standards written on the basic theory of the orifice covering every aspect. However, when a metering device is being considered for an operating location these additional factors should be considered. [8]

Meter tubes[14]

The meter tube is defined as the adjacent upstream and downstream piping that is attached to the orifice fitting. Once again, AGA Report #3 and the ISO 541 recommend the guidelines and the tolerances for the manufacture of these meter tubes. The selection of the pipe require round out tolerances that would be difficult to meet with a normal pipe. A normal commercial pipe does not meet these tolerances and this virtually eliminates the thought of field made meter tubes. Meter tube tubing is now available and it is made in sizes two inch through ten inch. The pipe walls of this meter run tubing are controlled to a very close degree, which results in a close tolerance finish of the inside pipe diameter. These tolerances will always better the tolerances as recommended by AGA Report #3 and ISO 541. This type of tubing should definitely be considered, as it is not logical to carefully bore orifice fitting and orifice flanges and then use pipe that would be out of round or exceptionally rough. The producer of the signal is received by the secondary element. As the secondary element cannot improve upon the signal that is produced by the primary element, all necessary care in the selection of materials and in the maintenance of the primary element should indeed be exercised.

Primary elements

The effects of pressure and velocity pulsations in the vicinity of the orifice constitute a very indefinite phase in the measurement of gas with an orifice meter. This pulsation can be of a low frequency form such as might result from reciprocating compressors, undamped pressure regulators, chattering valves, or liquid surging back and forth at low points of the line. It might also be a high frequency pulsation caused by resonance of the pipe lines themselves. The pulsations of lower frequency probably have a greater effect on the measurement; however, no conclusive information is at present available by which the pulsation errors can be completely correlated with pulsation frequency or with the wave form and the amplitude of that pulsations.[8]

To obtain reliable measurements it is necessary to suppress pulsations. The following items, in general, are valuable in diminishing pulsation and/or its effect on orifice flow measurement.

1- Locating the meter tube more favorable with regard to the source of pulsation such as at the inlet side of regulators, or increasing the distance from source of pulsation
2- Inserting capacity (volume) or specially designed filters in the line between the source of pulsation and the meter tube in order to reduce the amplitude of the pulsation.
3- Operating at differentials as high as is practical by installing a smaller orifice or by concentrating flow, in a multiple tube installation, through a limited number of tubes.
4- Using smaller sized tubes and keeping essentially the same size of orifice, while still maintaining the highest practical limit on the differential.

Effect of Water Vapor

In the measurement of gas containing moisture in a vapor state, the effect of the moisture depends largely on the specific gravity of the gas as shown in equation(7). Natural gas is quite dry, and its specific gravity is usually quite close to that of the water vapor, about 0.62. For this reason the only appreciable correction would be a direct volume correction based upon the partial pressure of the water vapor at flowing conditions.

$$\text{Specific gravity} = \rho\ \text{gas}/\ \rho\ \text{air} = \rho\ \text{gas}/28.9 \qquad (7)$$

Whereas the 28.9 g/mole is the molecular weight of the air

In the measurement of certain gases of known composition, the specific gravity is often calculated from the molecular weight or is determined from a moisture free sample. Under these conditions, especially with very light or very heavy gases, a correction must be made for the erroneous specific gravity obtained by having neglected the moisture content of the gas.

Recording or Calculating Equipment [8]

The final section of the measuring system that can materially affect your accuracy is the recording and calculating of the data obtained. Since all of the devices used for these jobs are secondary types of measuring equipment they must be calibrated against some standard. Likewise, when the metering devices are exposed to widely varying ambient conditions calibrations should be made covering the ranges encountered and if the effects are large enough, consideration should be given to controlling the environment in which they operate by adding housing, cooling, and heating. A balance between the accuracy required and the cost of obtaining it will determine the extent to which you can justify the testing and housing expenditures.

The indicated data must be either recorded or transferred to a central calculation office for conversion to flow rates or it may be calculated directly by equipment installed on site with mechanical, pneumatic, or electronic computers. Here again each step of recording or transducing and interpreting adds potential errors to the flow measurement so the simpler system with proper maintenance has been found to yield the best results.

Maintenance of the Meter Tube and Orifice[8]

Another source of error is the effect of time on the orifice and the meter tube. No known pipeline for natural gas is completely clean. The best that can be expected is a minimum of rust, oil vapors, condensed liquids, lubricating greases and the like. Any of these deposited on the plate and tube in the right places can cause errors of 5 to 10% easily. What this means to an operator is that the plate and the tube should be periodically inspected, cleaned and rechecked. Where sufficient money is involved, plates have been inspected on a once-a-week basis and the meter tubes on a once-a-year basis. Where there is less value being exchanged these tests may be made monthly on the plates and every other year on the meter tubes. Where sufficient solids (rust or sand) are present there may be a slow erosion of the square edge of the orifice and periodic replacement required. This is more often seen in the production rather than the pipeline measuring stations.

Wet Gas Measurement

The effect of liquid in the gas stream on measurement is a problem that has never been completely solved. Various arrangements of meter tubes, gage line piping, and drip pots have been used in an effort to minimize the errors resulting from liquid accumulation ahead of the orifice plate, at low points of the gage lines, or in the chambers of the meter manometer. An accumulation of liquid ahead of the orifice plate disturbs the normal flow pattern and alters the discharge coefficient for the orifice. Liquid trapped in the gage lines distorts the differential pressure and causes the manometer to give an incorrect indication. With bellow type manometers no error results from liquid being in the manometer chamber but in a mercury manometer the zero setting of the instrument will be altered because of a so called "wet-leg".

The effect of the mechanically entrained liquid that flows through the orifice in the form of mist is difficult to determine, because the amount of transported varies with time. The common practice has been to determine an average density for the mixture and presume that the flow rate corresponds to a fluid to that density. [13]

Advantages and disadvantages of Orifice meters[19]

Advantages

- In addition to not requiring direct fluid flow calibration, orifice meters are simple, rugged, widely accepted, reliable and relatively inexpensive.
- No moving parts.

Disadvantages

- Square root head/ flow relationship.
- High permanent pressure drop.
- Limited rangeability (4: 1).
- Tends to read low under abnormal conditions.

Venturi meter [4°]

A venture meter as illustrated in figure (42) can be used to measure the flow rate. In this meter the fluid is accelerated by its passage through a converging cone of angle (15-20°). The pressure difference between the upstream end of the cone and the throat are measured and provide the signal for the rate of flow. The fluid is then retarded in a cone of smaller angle (5-7°) in which large proportion of kinetic energy is converted back to pressure energy. Because of the gradual reduction in the area there is no vena contraction and the flow area is a minimum at the throat so that the coefficient of contraction is unity. Although venturi meters can be applied to the measurement of gas, they are most commonly used for liquids. And used for closed channel flow measurement.

Figure 42 On-line venture meter[4°]

2.2.4.2 Ultrasonic Flow Measurement

Ultra sonic can be divided into four basics types; time of flight (TOF), Doppler, cross correlation, and swept beam (Cascetta and vigo, 1988). The best known types are the convenient but not very accurate Doppler and the more accurate and more expensive (TOF). TOF has 2% accuracy for natural pipe line 6 to 30 inches in diameter. The TOF ultra sonic flow meter consists of two piezoelectric sensors located 180 degrees apart and separated by an axial distance, L, as shown in figure (43). When a voltage pulse is applied to sensor A, it changes its mechanical dimension alternately expanding and contracting and so generates an ultra sonic energy pulse. This pulse travels at sonic velocity through the fluid and is received by sensor B. the fluid velocity, V_f, is proportional to the difference between the transit times for the pulse to travel upstream, T_{BA} (from sensor B to sensor A), and downstream, T_{BA} (A TO B). VELOCITY IS GIVEN BY (Kyser downstream, 1988).

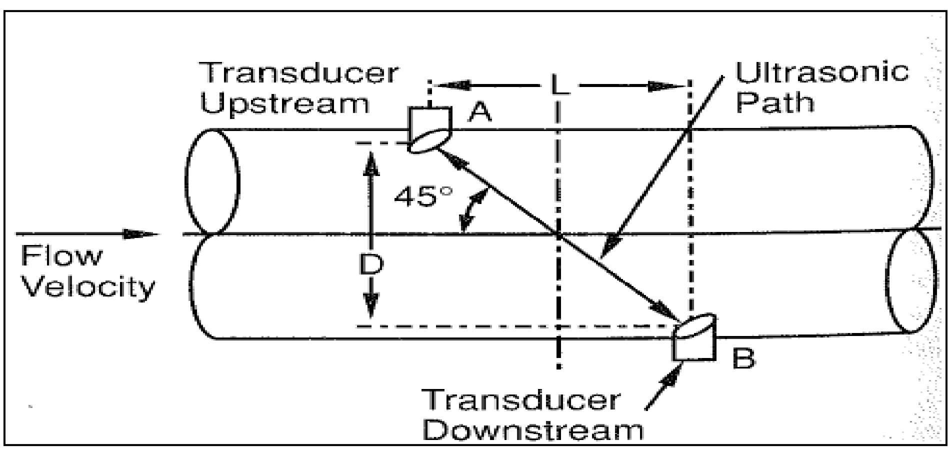

Figure 43 Pipe ultra sonic flow meter geometery (Scelzo and Munk, 1987)

Advantages and disadvantages of TOF Ultra Sonic meter[19]

Advantages

- No intrusion into pipe
- Wide rangeability (50:1)
- Easy to install (“clamp on”)
- Cost almost independent of size

Disadvantages

- The ultrasonic flow meter is an advanced measuring system which essentially meets the requirements for accurate and stable measurements.
- Periodic calibration required
- Accuracy not better than ±2%

There are a lot of different ultrasonic flow meters which measure mainly with two basic methods of measurement

- The principle of transit time difference
- The principle using the Doppler Effect

The measuring Principle of Transit Time Difference[12]

An acoustic (ultrasonic) signal is sent in both directions from one measuring sensor to another as shown in figure (44). A transit time difference arises because the signal propagation velocity of the sound waves is greater in the direction of flow than against the direction of flow.

This difference is directly proportional to the flow velocity. The flow can be calculated from the pipe cross-sectional area and the measured transit time difference. In addition to the volume flow the sound velocity of the fluid is always measured. The sound velocity can be used to distinguish different fluids or as a measure of fluid quality.

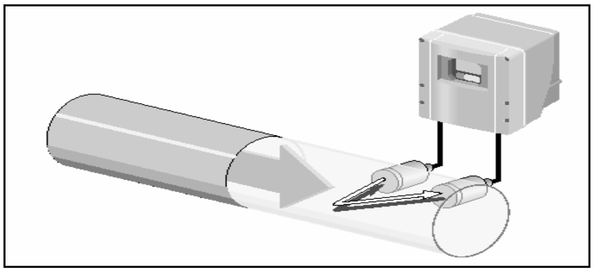

Figure 44 Measuring principle for transit time flow measurement[12]

Measuring system

The ultrasonic flow measuring system always consists of a transmitter and the related measuring sensors. The transmitter is used to actuate the measuring sensors. The measuring sensors work bidirectional as sound transmitters and sound receivers. The electrical signals of the transmitter are converted to a pressure signal in the measuring sensors and vice versa.

Clamp on sensors are mounted on the existing pipes from outside or the other type is inline sensors shown in figure (45). Clamp on sensors are mounted on the existing pipes from outside

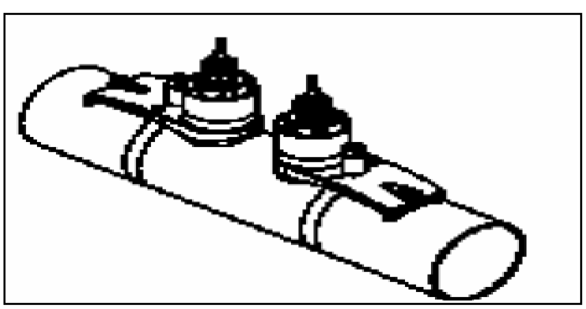

Figure 45 Clamp on and inline sensors[12]

Possibilities and applications

- Ideal for retrofitting, installation possible without interrupting process.
- Easy, quick and low-cost mounting.
- Suitable for all acoustically transmissive pipes and all pure and slightly contaminated liquids.
- Very large nominal diameter range DN 15-4000.

The principle using the Doppler Effect

Although the principle using the Doppler Effect is rarely used it is explained here to give a complete overview about ultrasonic measurement methods.

The Doppler Effect occurs if a relative movement between the transmitter and the receiver occurs as shown in figure (46). This relative movement is the so called “Doppler shifting “and results in an increase or in a decrease of the sonic wave frequency. For this kind of measurement it is crucial that the medium or fluid to be measured has inhomogenities (particles or gas bubbles) to be able to reflect the ultrasonic waves. To be able to measure Doppler meters need two sensors. The first sensor emits ultrasonic waves with constant frequency into the fluid that should be measured and the second sensor receives the reflected sonic waves. The reflection takes place at the particles or gas bubbles.

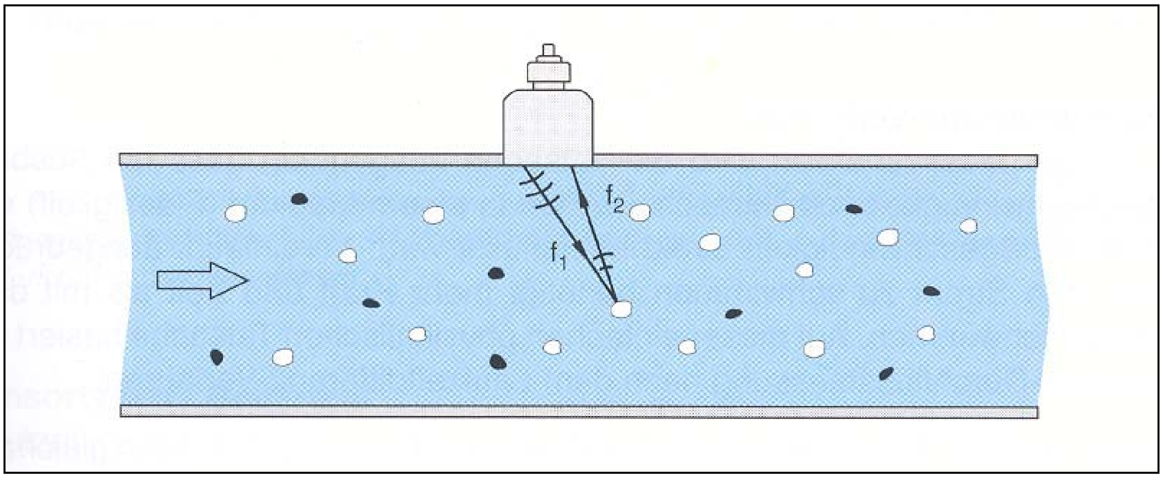

Figure 46 Ultrasonic measurements with the Doppler Effect[12]

The frequency of the reflected sonic waves is altered dependant on the particle velocity. The amount of frequency shifting is proportional to the flow velocity of the transported particles or gas bubbles. As long as the particle velocity is the same as the fluid velocity it is possible to determine the flowing velocity. The principle using the Doppler Effect is exact and simple as long as the velocity of only one particle is measured. In reality particles have different velocities, dependant on their position in the flowing profile of the pipe. As a consequence of this measurement results have to be "weighted." Another important effect is the deviation of the reflected wave at particles or gas bubbles on its way back.

The flow rate can be calculated by using equation (8)

$$\mathbf{Q = K * \Delta f} \qquad \mathbf{(8)}$$

Where **Δf**= shift of frequency (f1-f2),

f1 = the frequency of the emitted wave.

f2 = the frequency of the reflected wave.

K= constant which is a function of cross-sectional area, position of the reflecting particle, angle of incidence /angle of reflection.

ULTRASONIC FLOW METER U SZ 08 [5]

One of the ultrasonic meters products illustrated in figure (47), which has the following features

- For custody transfer applications
- High accuracy
- High stability to perturbations
- Easy to operate
- High flow velocity (up to 40 m/s) results in smaller
- nominal meter diameters
- maximum operating pressure 100 bar (250 optionally)
- Bidirectional measurements, i.e. measurements in both directions with automatic detection of the flow direction and separated totalizers for both directions. Ideal for underground storage facilities where the same line can be used for storing gas and withdrawing it.
- Suitable for operating pressures from 1 bar.

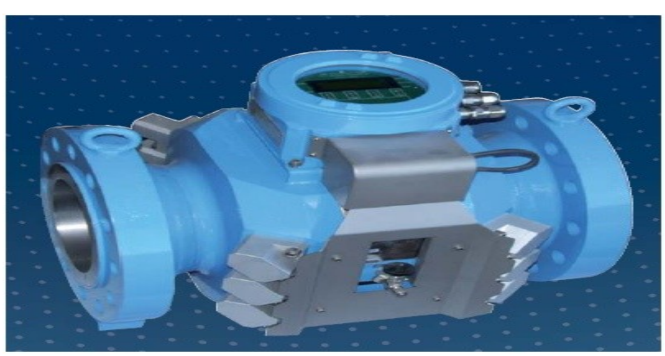

Figure 47 Ultrasonic flow meter u sz 08[5]

2.2.4.3 Vortex flow measurement

The vortex is designed to be installed directly into pipelines without need for special tools or complicated installations procedures. Make use of a natural phenomenon that occurs when a liquid flows around a bluff object. Eddies or vortices are shed alternately downstream of the object. The frequency of the vortex shedding is directly proportional to the velocity of the liquid flowing through the meter figure (48). [17] this phenomenon is readily visible when a flag waves in the breeze.

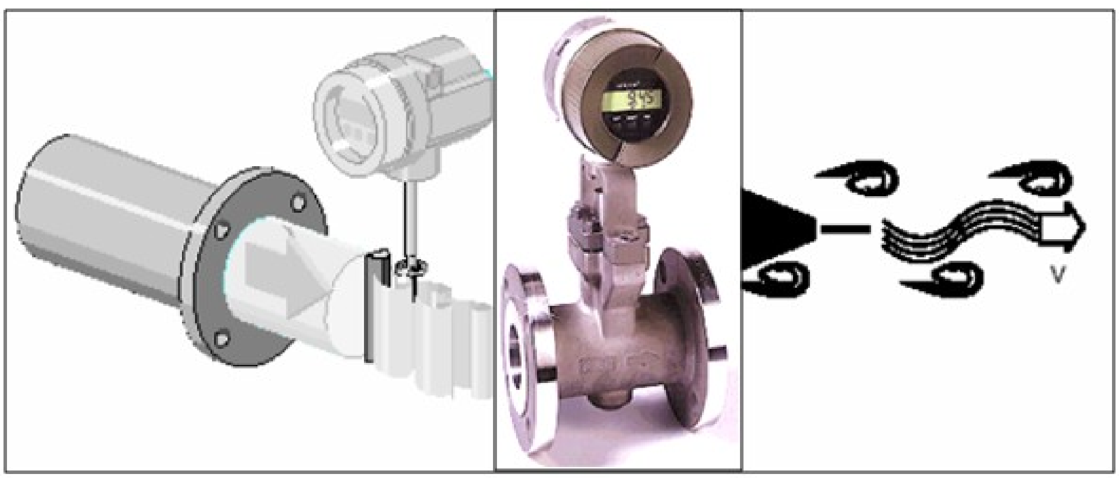

Figure 48 Measurement principle of Vortex flow meters[12]

The flag pole serves as the bluff obstruction and generates vortices that can cause the flag to wave. Such vortex shedding can produce sound as when a wire vibrates and signs in the wind. Note that vibrates are formed alternatively, first off one side of the body and then off the other side and are 180 degrees out of the phase.

Vortex is usually used piezoelectric crystals that act as force to charge transducers to detect these pressure fluctuations. Figure (49) shows Foxboro co. vortex flow meters usually use piezoelectric sensor. The three major components of the flow meter are a bluff body strut-mounted across the flow meter bore; a sensor to detect the presence of the vortex and to generate an electrical impulse, and signal amplification and conditioning transmitter whose output is proportional to the flow rate, the meter is equally suitable for flow

rate or flow tantalization measurements. Use for slurries or high viscosity liquids is not recommended. [17]

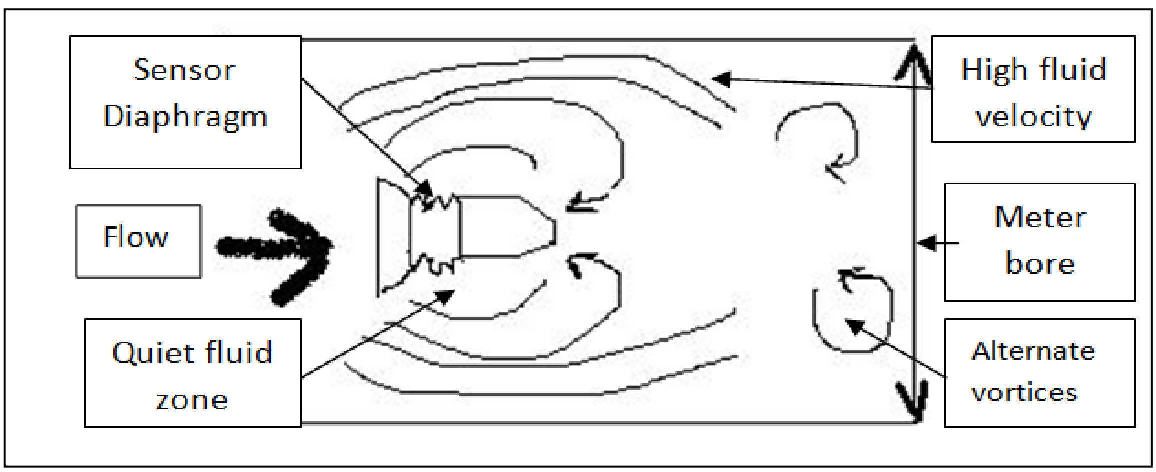

Figure 49 Vortex meter, Foxbore co. (Echeverria, 1985)[19]

The sensor of a vortex flow meter has a major influence on the performance, robustness and reliability of the whole measuring system. There are still intolerable levels of sensitivity to vibrations. This is not just the vibration that causes electronic components to fall off the printed circuit board. The vibrations of concern cause the vortex meter to indicate a flow where none is present. The meter is sitting there, mounted in the pipeline with no flow moving through it. Yet the output says there is 10%, 20%, or more being metered. The sensor of a vortex flow meter has a major influence on the performance, robustness and reliability of the whole measuring system. First generation vortex meter designs proved were very sensitive to vibration, fluid pulsation, and hydraulic noise.

Research continued, with one advance being the incorporation of piezoelectric crystal sensor technology into vortex designs. A key issue with piezoelectric crystals involves their sensitivity to large temperature gradients. In addition, the crystals are damaged in applications and service where pipe blow-downs routinely occur. There are still intolerable levels of sensitivity to vibrations. This is not just the vibration that causes electronic components to fall off the printed circuit board. The vibrations of concern cause the vortex meter to indicate a flow where none is present. The meter is sitting there, mounted in the pipeline with no flow moving through it. Yet the output says there is 10%, 20%, or more being metered.

Piezoelectric Crystal Sensors[12]

Most modern vortex meters use piezoelectric crystals as sensors. Piezoelectric crystals react to changes in stress and large temperature gradients. Pulsations and hydraulic noise can also flex the crystals and they react by giving a momentary output. In the case of the piezoelectric crystals the output will be a voltage spike. When there is flow in the pipe, the stress of the vortex shedding process generates a voltage spike that comes off the piezoelectric crystals.

The frequency of the spikes determines how high the meter output goes. Unfortunately, the piezoelectric crystal cannot differentiate between spikes created by the vortex shedding process or spikes generated by vibration. Various “fixes” to deal with this problem have been tried, with varying degrees of success.

One attempt to deal with this inherent noise issue raises the trigger level. However, for some application requirements, this may be unacceptable if the user cannot live with the reduced flow range capability. Another approach to deal with the noise issue involves installation of a proximity switch on the control valve. In this scenario, when the valve is shut, blocking flow through the pipeline, the power to the vortex meter is interrupted. A further attempt to eliminate this noise problem involved redesigning the meter bodies and sensor mountings. This allowed the shedder bar to flex, alleviating the stresses on the crystals. The design changes were also difficult to consistently manufacture. All these modifications are effective to some degree, but none are completely satisfactory. One very effective idea involves positioning of the meter in the correct orientation relative to Vibration. The direction of the vibration-induced travel is important. There are basically three planes of vibration.

Capacitive (DSC = Differential Switched Capacitance) Sensors

A better and extremely successful meter solution involves elimination of the piezoelectric crystal, substituting an entirely different sensor. The capacitance (DSC) sensor as shown in figure (50) design solves the vibration problem better than other systems. Instead of a piezoelectric crystal, a balanced capacitance sensor is employed. This sensor is located just behind the shedder bar. As the vortex swirl is generated, a small differential in pressure is generated between the two sides of the bluff body. The sensor then deflects very slightly (micro-inches) from one side to the other, causing one side of the central electrode to get closer to one capacitor plate and further from the other plate. This generates a pulse spike.

Shedding of the next vortex swirl causes the sensor to deflect in the opposite direction, where another pulse spike is generated. The sensor consists of an upper and lower portion. The lower portion is in the flow stream. The upper portion is isolated by the flexure. The two portions of the sensor are balanced; they both have the same mass distribution. Therefore, when there is vibration in the pipeline, the vibration affects both the top and bottom portions in the same way.

As a result, the capacitor plates do not become any closer together or further apart; and no output spike is generated. If no pulse spike is generated, there is no output from the vortex meter electronics. The desired result is achieved; when there is no flow through the meter, no output signal is generated.

The DSC sensor advance provides these key benefits:

- High vibration immunity (> 1g, 20-500Hz, all directions)
- Resistance to thermal shock and water hammer
- One sensor for all meter diameters
- Insensitivity to dirty flows

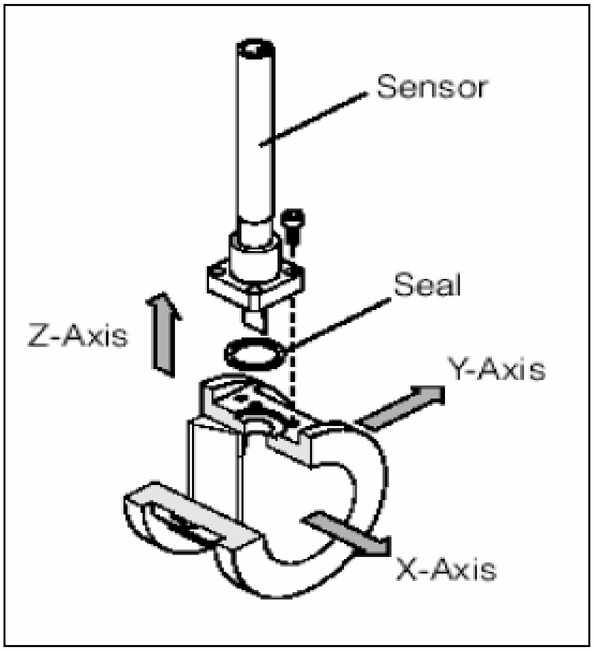

Figure 50 Capacitive sensor and the vibration planes[12]

Advantages and disadvantages of Vortex meters [19]

Advantages

- Good rangeability 30: 1.
- No moving parts.
- High temperature range (-200 … +400°C)
- Accuracy up to ± 1% of the maximum
- Good linearity over operating range.

Disadvantages

- Not suitable for dirty/ abrasive fluids
- Appreciable pressure drop
- At lowest velocity Re >104
- Susceptible to flow pattern inhomogenities (long inlet and outlet runs).

2.2.4.4 Coriolis (Mass) Flow Measurement

The Coriolis flow measurement is at the moment the only measuring principle that directly measures flowing masses. The most striking advantage of this system is that the mass of a system is independent of outer physical influences like pressure, temperature, density and viscosity. The other measuring systems depend on volumetric and are therefore less accurate than this mass measurement system. High accuracy and reliability of this system make it especially interesting for measurement in case of trade.

Measuring principle[12]

The measuring principle is based on the controlled generation of Coriolis forces as expressed in equation (9). These forces are always present when both translational and rotational movements are superimposed.

$$F_C = 2 * \Delta m (v) * (\omega * v) \qquad (9)$$

Where F_C = Coriolis force

Δm = moved mass

ω = angular velocity

v = radial velocity in the rotating or oscillating system

The amplitude of the Coriolis force depends on the moving mass m, its velocity (V) in the system and thus on the mass flow. Instead of a constant angular velocity the sensor uses oscillation. The measuring tube contains flowing fluid and oscillates. The Coriolis forces produced at the measuring tube causes a phase shift in the tube oscillations see illustration in figure (51).

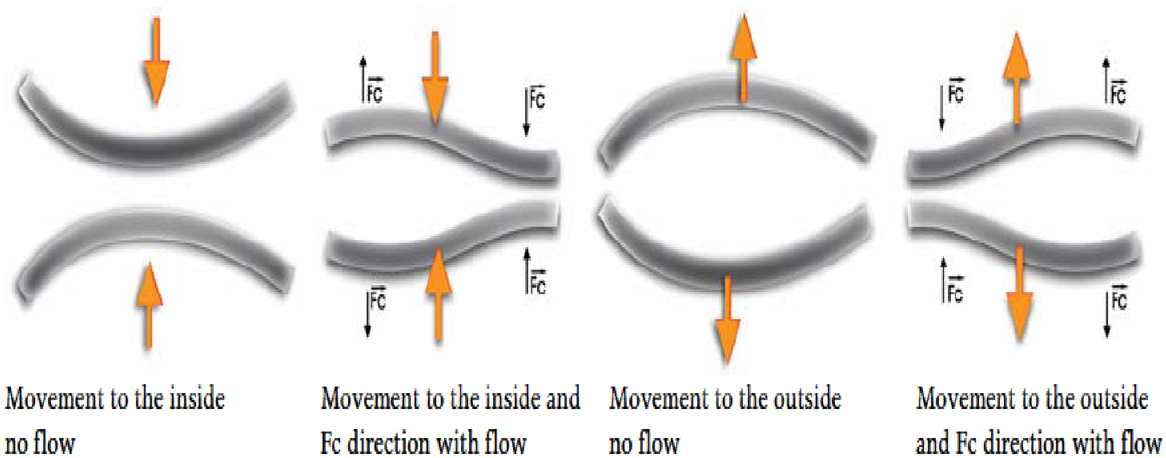

Figure 51 Coriolis forces and oscillation in measurement tubes

2.2.4.5 Turbine meters

Turbines are typically considered to be a repeatable device used for accurate measurement over large and varying pressures and flow rates. They are found in a wide array of elevated pressure applications ranging from atmospheric conditions to 1440 psig. The turbine meter of today offers a reliable and repeatable form of gas measurement. A wide variety of both mechanical and electrical readouts, coupled with low pressure drop and good rangeability , make this form of measurement a popular one. Dual rotor turbines have added to this attraction by creating a turbine that provides compensation to typical mechanical problems as well as undesirable flowing gas conditions. As with most inferential measurement devices, care should be taken to create a piping configuration indicative of a uniform flow profile. Proper sizing, installation and maintenance procedures are critical in maintaining the desired performance and longevity of these devices.

A Turbine meter is one in which the primary element is kept in rotation by the linear velocity of the stream in which it is immersed. The number of revolutions the device makes is proportional to the rate of flow. Today turbine meters are available for gas measurement in sizes and working pressures ranging from 0.24 to 3.36 [MMscf] and 175 to 1440 [psig]. In principle, gas turbine meters are the same as for liquids, with a few important differences. Since the driving torque is proportional to the density of the flowing fluid, this torque is much lower gas than for liquids. The rotor speed is therefore maintained high by operating at high pipeline velocities and by having a high ratio of center body diameter to pipe diameter. A nose cone or flow deflector forces the gas to flow through an annulus having an open area approximately one-third of the open pipe area, thus providing more driving torque. The nose cone also absorbs most of the flow stream thrust that otherwise might damage the rotor bearings. The rotor spins at similar speeds than those for liquids, and hence smaller blade angles are used (10 degrees) compared to liquids (35 degrees). The rotor blades are often helical rather than flat and are machined or moulded as an integral part of the hub to improve strength.

Because light weight improves rotor performance and bearing life, high strength, impact resistant plastic or alumina is normally used. Bearings are usually of the ball race type and small relative to the meter partly to reduce frictional drag and partly due to the high rotational speed. The nose cone usually shields the bearings from liquids, dirt, and grit entrained in the flowing gas. Bearings must be lubricated either permanently or periodically There are two distinct methods of measuring rotor rotation mechanical or electro-magnetic. Mechanical designs use gear trains connected to a counter clock. There are four types of electro-magnetic sensors - induction pickup coil, reluctance pickup coil, modulated carrier pickup coil and light emitting diode sensor. Due to the large contraction area, gas meters tend to be less influenced by inlet conditions than liquid meters. Nevertheless, some 20 pipe diameters are recommended as the minimum inlet length even though the flow standards that are appearing suggest 10 diameters as a minimum length.

Construction of Turbine Meters

1. Housing - a flanged pipe spool as shown in figure (52) from 0.25 to 24 [in] diameter with 275 - 6000 psig working pressure and -20 to +500 [°F] standard design temperature. Construction material is usually carbon steel or stainless steel for corrosive environments or low temperature applications.
2. Upstream and Downstream Hangers (or stators, supports) - which center and support the rotor and axially clamp the rotor thrust bearings. These hangers contain the thrust washers, provide passages for hydraulic thrust balancing of the rotor, and include blades for straightening the flow.
3. A Rotor - with stainless steel blades supported by tungsten carbide journal bearings and thrust washers. These tungsten carbide bearings are highly polished and have a small bearing

surface to minimize drag. In modern designs the rotor “floats” between the upstream and the downstream cones on a thin film of liquid that flows between the bearing and the shaft. The rotor is thrust upstream by the pressure difference across the rotor blades and downstream by the flow impinging on the outer rim of the rotor hub which is, by design, not shielded by the upstream cone.

4. A variable Reluctance Pick-Up Coil which detects the rotational speed of the rotor by monitoring changes in magnetic flux passing through the coil bobbin. The rotor must have regularly spaced paramagnetic material at the periphery for the variable reluctance pickup to work. The turbine meter, the flowing gas velocity is represented by the rotation of the rotor itself. The speed or rotation of the rotor is directly proportional to the rate of flowing gas. Flowing gas enters the inlet of the turbine meter and is immediately directed through a smaller channel created by the annular passage between the body and nose cone as can be seen in figure (53). The purpose of the nose cone is to straighten or condition the flowing gas as well as provide a restriction. This restriction effectively reduces the cross-sectional area of the body, thus increasing the velocity of the flowing gas. Increasing the velocity of the flowing gas is critical to a turbines performance as the kinetic energy also increases proportionally. By definition, kinetic energy is the physical energy of mass in motion. More importantly, kinetic energy is the driving force behind the operation of a turbine style device.

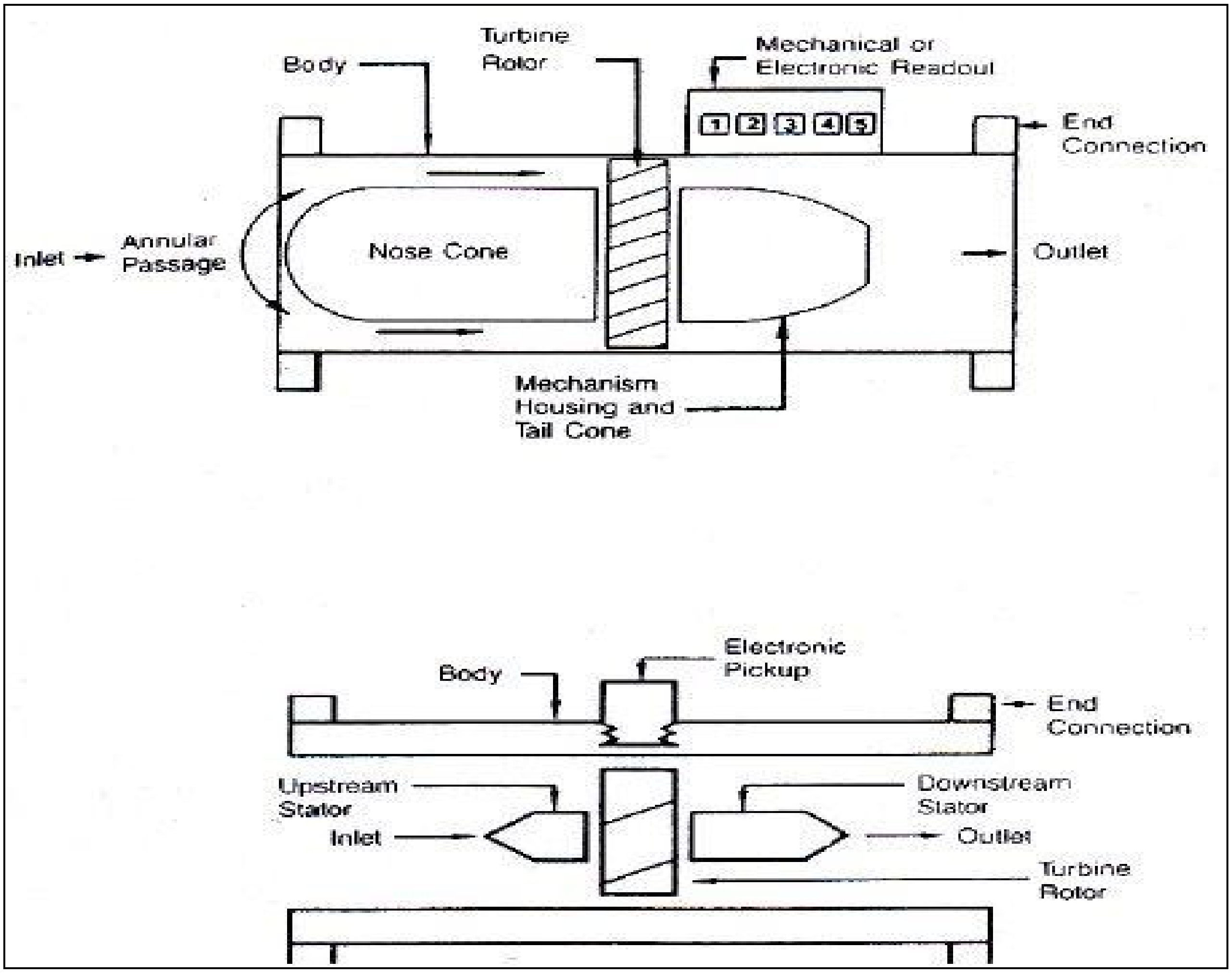

Figure 52 Gas Turbine meter[19]

Operating Problems of the turbine meters[16]

Overloaded meters and/or poor gas quality are the major problems. The turbine meter should not be operated continuously at over 70% of the rated capacity. Entrained liquids as water and/or hydrocarbons tend to wash the lubricants out of the ball bearings.

Advantages and disadvantages of Turbine meters[19]

Advantages

- Very good repeatability and reliability
- High rangeability 10: 1
- Low pressure losses
- High pressure and temperature range for application
- High accuracy at defined measurement conditions (measurement range, viscosity).

Disadvantages

- Moving parts subject to wear
- Bearings damaged by over speeding, corrosion
- Rather expensive
- Dirty fluids must be filtered
- Susceptible to flow pattern inhomogenities (long inlet (10xDN) and outlet
- Runs (5xDN)).

MAINTENANCE[16]

As with most mechanical devices turbine meter bearings require lubrication, the three most common methods of turbine lubrication are gravity feed, pressurized pump guns and automatic oilers. The simplest technique, gravity feeding, requires no equipment as the recommended oil is fed into the external lubrication valve directly from the bottle. The pressure feed requires the use of a pump gun capable of containing full line pressure. This method is often preferred as the gun pushes new oil into the rotating bearings as the old, contaminated oil is forced or flushed outward. The third method utilizes an automatic lubricating device. This method dispenses a preset volume of lubricating oil into a turbine based on time increments or volume measured. While costly, this approach has become popular for remote locations where manpower and time is at a premium.

By conducting a spin test the technician can determine if excessive levels of mechanical friction are acting upon the turbine. High levels of friction may result in mechanical binds, loss registration or a catastrophic failure under severe conditions. The spin test provides a useful tool in establishing both lubrication schedules as well as module removal frequencies. Although a critical part of routine turbine maintenance, it is important not to substitute the spin test for other pertinent procedures, such as the visual inspection and re-calibration checks. The operator must bear in mind that it is possible for a turbine to achieve an acceptable spin test while being grossly out of calibration. For example, installing the wrong timing gears on a meter may affect the performance accuracy by several percent. However, this meter may still pass a spin test. Although rare, it is feasible that a rotor missing one or more blades could also pass this procedure. The spin test should be considered only one integral part of a turbine meter maintenance program.

Turbine Meter TRZ 03-TE/TEL

Turbine Meter TRZ 03-TE/TEL is one of the turbine meter products as shown in figure (53) which has the following Featuresf

- For custody transfer applications, One of the electronic gas meters
- LF and HF pulse transmitters in the meter head
- DIN-DVGW-tested and PTB-approved
- Electronic totalizing unit (battery-operated, min. service life 6 years)
- Digital transmission of totalizer readings is possible
- Flow display
- Current output (external power supply unit required)
- Design also suitable for corrosive media (biogas, etc.

Turbine Meter TRZ 03-TE/TEL applications

- Maximum operating pressure 100 bar
- Rating ranges 13-25000 m3/h

Figure 53 Turbine Meter TRZ 03-TE/TEL[5]

2.2.5 Water content of natural gas

To water content is determined using gas chromatograph as shown in figure (5) in chapter one. The sample mixture must be capable of vaporization without undergoing decomposition so that it can then be transported in gaseous form by an inert carrier gas through a separating column. The individual sample components are separated by the column on the basis of their different boiling points and the intermolecular interactions between the liquid, stationary phase in the separating column and the sample components in the mobile gas phase. The individual gas fractions existing in the column are usually detected by thermal conductivity (Tc). This analysis method allows several liquid sample components to be analyzed at the same time. Gas chromatography is suitable for liquid samples with moderate solids content and water content greater than 5%, as well as for samples whose water can be removed by extraction.

2.2.6 Emissions waste

In the case of gas, there are limits on water content, energy content (BTU content), and mole fractions of non hydrocarbon gases such as N2, CO2, H2S, (API 1989). These emissions are difficult to quantify with a high degree of accuracy and there remains substantial uncertainty in the values Natural gas plants another source of the emissions waste. These plants provide a centralized facility to efficiently dehydrate, compress, and extract non hydrocarbon diluents from natural gas and to extract natural gas liquids. The relative roles of gas plants and well production facilities vary. Some gas plants accept full well stream, some accept gas separated at the lease, and the others essentially “straddle” a gas pipe line that is transporting marketable natural gas. While methane is the principle component of natural gas, many natural gases contain significant fractions of ethane, propane, butanes, and heavier NGLs. Non hydro carbon diluents such as CO2, N2, and H2S are very common. Water, free hydrocarbon liquids, mercaptan, solids, scale, sludge, and other impurities may also be present. Most of the fugitive greenhouse gas emissions from the oil and gas systems are methane losses from production activities, natural gas processing, transportation and distribution. The amount of fugitive emissions per unit of throughput tends to decrease downstream through both types of systems (for example, specific fugitive emissions of greenhouse gases are usually much greater from gas production than gas distribution). SO2 emissions are attributed to the flaring or incineration of sour waste gas and acid gas streams, and to inefficiencies in sulphur recovery units at sour gas processing plants, upgraders and refineries. CO emissions are a product of all flaring and incineration activities.

Emissions assessment in oil system

The total amount of associated and solution gas produced with the oil is assessed, and then control factors are applied to the results to account for conserved, reinjected and utilized volumes. The result is the amount of gas either flared or lost directly to the environment (whether through equipment leaks, evaporation losses or process venting). The flared, utilized and conserved volumes are determined from available production accounting data and engineering estimates.

The rest of the gas, by difference, is lost directly to the atmosphere. The total amount of associated gas per unit volume of oil production is given by the gas-to-oil ratio (GOR) for the target oil fields. The amount of solution gas or product volatilization per unit oil production is determined from the change in product vapor pressure between the inlet separator at the field production facility (i.e., the vessel operating pressure) and the refinery inlet (e.g., a Reid vapor pressure of 30 to 55 kPa). The gas losses classification of the natural gas facilities is given in table (4).

Emissions measurements methods

1- **Leak detection**

To show changes in emissions from fugitive equipment leaks (a large if not the largest source of organic emissions at many facilities) requires the performance of regular leak detection and repair programs. Furthermore, conventional technologies used in leak detection and repair programs (i.e., estimation of leak rates based on leak screening data collected in accordance with US EPA's Method 21) provide only a very crude indication of actual changes in emissions. According to Lott et al. (1996), the typical error from use of such approaches is ±300 percent or more depending on the number of components considered and the actual method used to estimate leak rates from the screening values (i.e., emission factors or leak-rate correlations). Since nearly all the emissions come from the small percentage of components that leak the most, a good approach might be to conduct a simplified screening programs to identify these few leaks and then use direct measurement techniques (e.g., High-Flow sampler [Lott et al., 1996], flow-through flow meters, and bagging techniques) to accurately measure their actual leak rates. For there are some measurements must be done either for quality control, safety or monitoring reasons. One of the monitoring reasons is gas detection. There are many mechanisms for that. EYE-C-GAS Infrared camera for gas detection as shown in figure (54) .which is designed for Petrochemical, Oil and Gas markets.[47]

Figure 54 Eye-c-gas infrared gas detection

2- **Empirical Correlations**

Examples of empirical correlations include the various API (1997, 1996, 1991, and 1987) algorithms for determining evaporation losses from storage tanks and product loading/unloading terminals, and leak-rate correlations for converting leak screening data to emissions rates (GRI Canada, 1998; US EPA, 1995b).

3- **Empirical Correlations**

Examples of empirical correlations include the various API (1997, 1996, 1991, and 1987) algorithms for determining evaporation losses from storage tanks and product loading/unloading terminals, and leak-rate correlations for converting leak screening data to emissions rates (GRI Canada, 1998; US EPA, 1995b).

4- Direct Measurement Techniques

these techniques include duct or stack flow measurements, bagging (US EPA, 1995b), high-flow sampler (Lott et al., 1996), isolation flux chambers (Kienbusch and Ranum, 1986; Kiennbusch, 1986), and portable wind tunnels (Schulz et al., 1995; Jiang and Kaye,1997). The latter two methods are applicable for measuring volatilization rates from sources such as exposed oil sands, contaminated soils and land farm operations. Overall, direct methods tend to offer the greatest potential accuracy but are only amenable to relatively simple point sources or applications where a high degree of specificity is required.

5- Indirect Measurement Techniques

These include remote sensing (Scotto et al., 1991; Piccot et al., 1996; Minnich et al. 1991), the plume transect method (Mickunas et al., 1995; Piccot et al., 1996;Balfour and Schmidt, 1984), and tracer methods (McManus et al., 1994; Lamb et al., 1995, 1994). Indirect methods are best suited for a lumped-analysis of large complex sources.

Table 4 Classification of gas losses[43]

Classification of gas losses as low, medium or high at selected types of natural gas facilities					
Facilities	**Activity Factors**	**Low**	**Medium**	**High**	**Units of Measure**
Production and Processing	Net gas production (i.e., marketed production).	0.05	0.2	0.7	% of net production
Transmission Pipeline Systems	Length of transmission pipelines.	200	2 000	20 000	m^3/km/y
Compressor Stations	Installed compressor capacity.	6 000	20 000	100 000	m^3/MW/y
Underground Storage	Working capacity of underground storage stations.	0.05	0.1	0.7	% of working gas capacity
LNG Plant (liquefaction of regasification)	Gas throughput.	0.005	0.05	0.1	% of throughput
Meter and Regulator Stations	Number of stations.	1 000	5 000	50 000	m^3/station/y
Distribution	Length of distribution network.	100	1 000	10 000	m^3/km/y
Gas Use	Number of gas appliances.	2	5	20	m^3/appliance/y

Source: Adapted from currently unpublished work by the International Gas Union, and based on data for a dozen countries including

Chapter 3

3. Petroleum fluids Storage and transportation and their measurements

3.1 Introduction

There are a specification for both oil and gas to be ready for transportation. For crude oil transportation as shown in figure (54), the accurate metering of mass is desirable for equity consideration. For tanker transport, a stringent vapor pressure specifications necessary. Also, the removal of any toxic materials especially hydrogen sulfide from the crude oil prior to delivery is required. For natural gas production transportation must be treated to remove the heavy hydrocarbons which will condense if the temperature reduced. Very rich streams may produce more than 1000 m^3 liquid condensate per million m^3 of gas produced.

3.2 Crude oil transportation

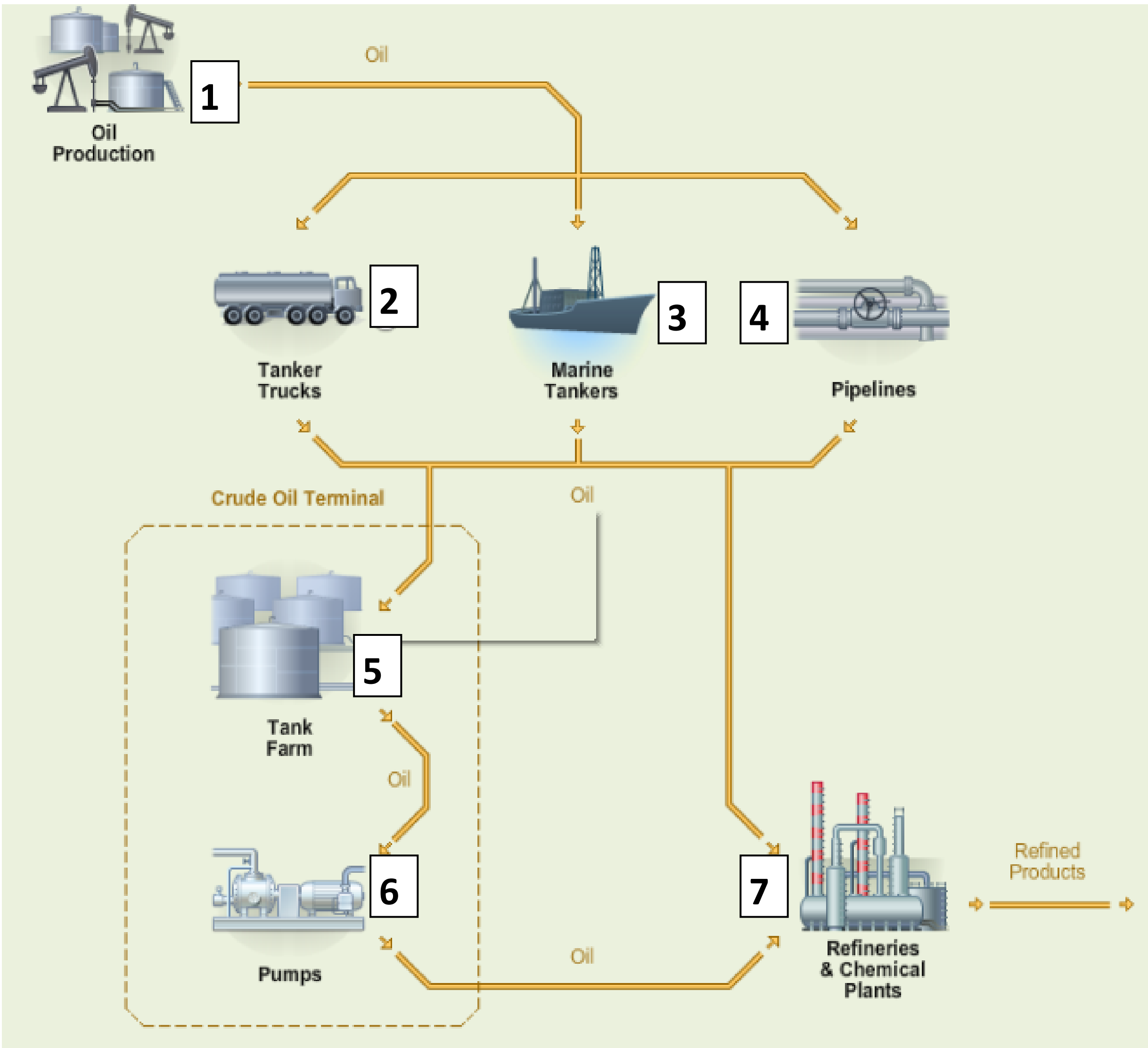

Figure 55 Cycle of crude oil transportation[2]

Definitions of crude oil terminal figure (55)

1-oil production: The output of crude oil from geologic reservoir extraction operations.

2-Tank trunk: Includes all road vehicles carrying liquid or gaseous cargo in bulk.

3-Marine tankers: Any ship or other watercraft carrying liquid or gaseous cargo in bulk.

4-Pipelines: A network of pipes used to transport gases and liquids.

5-Tank farm: System or arrangement of tanks, interconnecting pipelines, pumps or other surface equipment associated with the bulk storage of hydrocarbon liquids.

6-Pumps: Mechanical devices used to cause liquids to flow by physical displacement.

7-Refineries and chemical plants: A plant where crude oil is separated by distillation into many boiling range fractions each of which are then converted by various secondary processes often employing catalysts and further fractionation or purification steps such as cracking, reforming, alkylation, polymerization and isomerisation, into usable products, blending stocks or feed stocks for other processes. The secondary unit products are combined in the product blenders to meet specifications of finished commercial products commonly including but not limited to: ethylene, propylene, benzene, toluene and xylenes (for petrochemicals); grades of gasoline, diesel and fuel oils; waxes, lubricants and greases; residual fuel oil, asphalt and petroleum coke. The following table (5) gives the typical crude oil pipe line transport specifications.

Table 5 Crude oil pipe line transportation specification

Characteristic	Value (Goar and Arrington, 1978)
Solid and water content	< 1.0 wt%
Pour point	< 50 ˚F
Sour crude RVP	>0.5 wt% sulfer ASTM D 1552 < 9.5 psia (at 100˚F)
Sweet crude RVP	>0.5 wt% sulfer ASTM D 1552 < 0.8 to 10.0 psia (at 100˚F)
Viscosity	< 325 SSU AT 60˚F.

3.3 Crude oil storage measurements

System or arrangement of tanks, interconnecting pipelines, pumps or other surface equipment associated with the bulk storage of hydrocarbon liquids. In this system the tank liquid level is measured beside the temperature and pressure. An accurate measuring is required of the volumes transferred to and from storage to avoid loss. Measurement of crude oil also involves more than total volume. Crude oil usually contains entrained water and sediment (bottom sediment and water, or BS&W). Traditionally, the volume of sediment and water has been measured and the total volume passing the meter has been corrected when payment is made. Water content can be measured both manually and automatically. On the lease, a leas automatic custody transfer (LACT) unit contains pumping, metering, and BS&W measuring equipment. The unit automatically begins pumping from a lease storage tank into the crude gathering pipeline. When the pump has lowered the liquid in the lease tank to a prescribed level, the LACT unit shuts off automatically. Determing BS&W. Determining BS&W content with automatic devices normally depends on measuring electrical characteristics of the stream. Crude and water have different electric resistance properties, allowing the detection of water in crude oil stream.[5°]

3.3.1 Tank level measurement

The oil industry generally prefers displacement-type level sensors; because of user familiarity and the availability of spare parts (The petroleum industry will use d/p cells when the span exceeds 60-80 in. If the tank is agitated, there is often no space in which to insert probe-type sensors, because the liquid surface is not flat, sonic, ultrasonic, or radar devices typically cannot be used, either. Even with displacer or d/p sensors, agitation can cause the level signal to cycle. These pulses can be filtered out by determining the maximum rate at which the level can change (due to filling or discharging) and disregarding any change that occurs.

The relationship between level and tank volume is a function of the cross-sectional shape of the tank. With vertical tanks, this relationship is linear, while with horizontal or spherical vessels, it is a non-linear relationship. A Level Measurement Orientation On the 28th of March 1979, thousands of people fled from Three Mile Island (near

Harrisburg, PA) when the cooling system of a nuclear reactor failed. This dangerous situation developed because the level controls turned off the coolant flow to the reactor when they detected the presence of cooling water near the top of the tank.

Unfortunately, the water reached the top of the reactor vessel not because there was too much water in the tank, but because there was so little that it boiled and swelled to the top. From this example, we can see that level measurement is more complex than simply the determination of the presence or absence of a fluid at a particular elevation.

Level Sensor Selection

When determining what type of level sensor should be used for a given application, there are a series of questions that must be answered

- Can the level sensor be inserted into the tank or should it be completely external?
- Should the sensor detect the level continuously or will a point sensor be adequate?
- Can the sensor come in contact with the process fluid or must it be located in the vapor space?
- Is direct measurement of the level needed or is indirect detection of hydrostatic head (which responds to changes in both level and density) acceptable?

- Is tank depressurization or process shut-down acceptable when sensor removal or maintenance is required?

By evaluating the above choices, one will substantially shorten the list of sensors to consider. The selection is further narrowed by considering only those designs that can be provided in the required materials of construction and can function at the required accuracy, operating temperature, etc. (Table 4). When the level to be measured is a solid, slurry, foam, or the interface between two liquid layers, it is advisable to consult not only Table 4, but other recommendations, such as Table 5. If it is found that a number of level detector designs can satisfy the requirements of the application, one should also consider the traditions or preferences of the particular plant or the particular process industry, because of user familiarity and the availability of spare parts. For example, the oil industry generally prefers displacement-type level sensors, while the chemical industry favors differential pressure (d/p) cells. (The petroleum industry will use d/p cells when the span exceeds 60-80 in.)

If the tank is agitated, there is often no space in which to insert probe-type sensors. Additionally, because the liquid surface is not flat, sonic, ultrasonic, or radar devices typically cannot be used, either even with displacer or d/p sensors, agitation can cause the level signal to cycle. These pulses can be filtered out by first determining the maximum rate at which the level can change (due to filling or discharging) and disregarding any change that occurs faster than that. The relationship between level and tank volume is a function of the cross-sectional shape of the tank. With vertical tanks, this relationship is linear, while with horizontal or spherical vessels, it is a non-linear relationship. If the level in a tank is to be inferred using hydrostatic pressure measurement, it is necessary to use multi-transmitter systems when it is desirable to[8]

- Detect the true level, while either the process temperature or density varies.
- Measure both level and density.
- Measure the volume and the mass (weight) in the tank.

By measuring one temperature and three pressures, the system shown in figure (56) is capable of simultaneously measuring volume (level), mass (weight), and density, all with an accuracy of 0.3% of full span. [8]

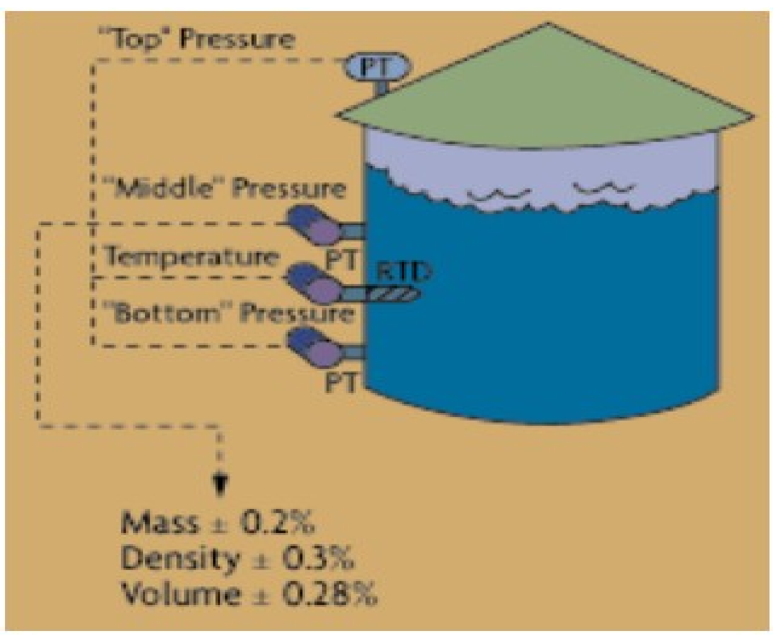

Figure 56 Intelligent multi transmitter package[8]

3.3.1.1 Maglink level transmitter[39]

The measurement principle of Maglink level transmitter that is shown in figure (57) can be summarized as following; the indicator head is mounted directly on top of the guiding tube. The guiding tube is completely sealed towards the inside of the tank. A stainless steel wire is attached to a spring actuated drum located within the indicator head. The other end of the wire is fixated to a stainless steel plate that works as an end stop at high level. The plate is connected to a magnet (follower magnet) via a stainless steel wire (offset wire). This magnet is placed inside the guiding tube. The float contains an annular magnet. It actuates a magnetic coupling between the float and the follower magnet. A change in level causes a linear transmission to the indicator head through the wire as the float rises or sinks along the guiding tube. A high precision gearbox with clockwork motor compensates for the weight of the follower magnet and eliminates any backlash of the indication. A precision drum retains the wire. The standard indication head is equipped with two pointers. The red pointer indicates meters or feet and the black pointer centimeters or inches while the respective measuring ranges have the same color on the scale.

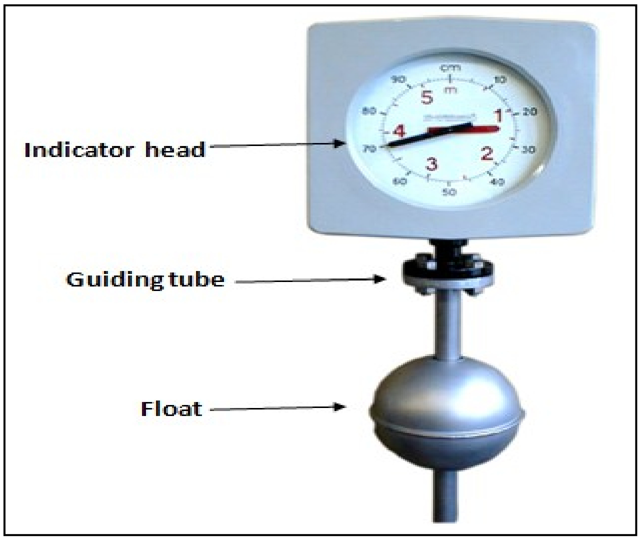

Figure 57 Maglink level transmitter[39]

1.3.3.2 Hart level transmitter

Hart level transmitter **-** 244LVP illustrated in fig (58) is level measurement with displacer for measurement of level, interface or density of liquids, with high accuracy, even under difficult conditions such as high pressure, high temperature and corrosive liquids, even in explosive atmospheres. The extensive product line gives you solutions for almost every application.

Ruggedized design and high reliability, easy configuration via digital communication and local LCD, long design life and freedom from maintenance reduces the effective costs running your plant and increases its profitability. The measurement with the displacer method, the buoyancy force of the displacer is measured depending on the level.

$$K_{A} = h_{f} * \prod * (r_{A}\hat{}2) * g * (\rho_{A} - \rho_{f}) + (L - H_{f}) * * \prod * (r_{A}\hat{}2) * g * (\rho_{a} - \rho_{g}) \qquad \textbf{(10)}$$

Where K_A= Buoyancy force, is measured by the transmitter as a measure for the level, N

r_A = Displacer diameter, m

L = length of the displacer, m

ρ_A = Density of the displacer, kg/m3

ρ_f = Density of the liquid, kg/m3

H_f = liquid height of the displacer, m

P_g = Density of the gas/steam, kg/m2

g = Acceleration due to gravity 9.81 m/s2

Figure 58 Hart level transmitter - 244LVP [7]

Features of HART level transmitter - 244LVP

- Process temperature –50 to +150 °C (–58 to +302 °F)
- Process pressure vacuum to 40 bar /ANSI Class 300

- Level measuring range 0 to 50 mm up to 0 to 3 m/ 0 to 2 inch up to 0 to 10 feet
- Measuring of density
- Sensor with no moving parts
- Accuracy ± 0.2 %

Influence in the Process[7]

- Temperature is very little influence
- Pressure is very little influence
- Steam, Fog has no influence
- Dielectric constant has no influence
- Foam has no influence
- Vibrations are minimized due to Smart Smoothing + Damping
- Motion of Fluid has very little influence (if necessary use protecting tube or displacer chamber)
- Diffuse Interface has no influence
- Displacer stroke is zero (no position alteration at liquid level change)
- Corrosive Fluids has no influence (instruments are delivered in resistant materials)
- Vessel material has no influence
- Deposits on vessel has no influence
- Deposits on displacer has very little influence

3.3.1.3 Radar level measurement[34]

Radar level measurement shown in fig (59) is based on time delay measurement between emitted radar impulses and on the surface of the product reflected and received radar impulses. The Tank Side Monitor NRF590 is sensor integration and monitoring unit for bulk storage tank gauging applications.

Figure (59) NRF590 sensor – radar level measurement[34]

Features of NRF590 sensor

- Ambient temperature -40°C to 60°C (-40 °F to 140 °F)
- Weights & Measure-approved for use in custody transfer applications
- Approved for use in explosion hazardous areas

Application

- The Tank Side Monitor NRF590 is a field device for the integration of tank sensors into tank inventory systems. It is used in tank farms, terminals and refineries. Especially, it can be used in connection with Micro pilot M level radars (for inventory control) and Micro pilot S.

- High accuracy level radars (for custody transfer applications).

Operating principle

The Tank Side Monitor is typically installed at the bottom of the tank as shown in figure (60) and allows to access all connected tank sensors. Typical process values measured by the sensors are

- level
- temperature (point and/or average)
- water level (measured by capacitive probe)
- hydrostatic pressure (for hydrostatic tank gauging, "HTG", or hybrid tank measurements, "HTMS")
- secondary level value (for critical applications)

The Tank Side Monitor collects the measured values and performs several configuration tank calculations. All measured and calculated values can be displayed at the on-site display. Via a field communication protocol, the Tank Side Monitor can transfer the values to an inventory control system.

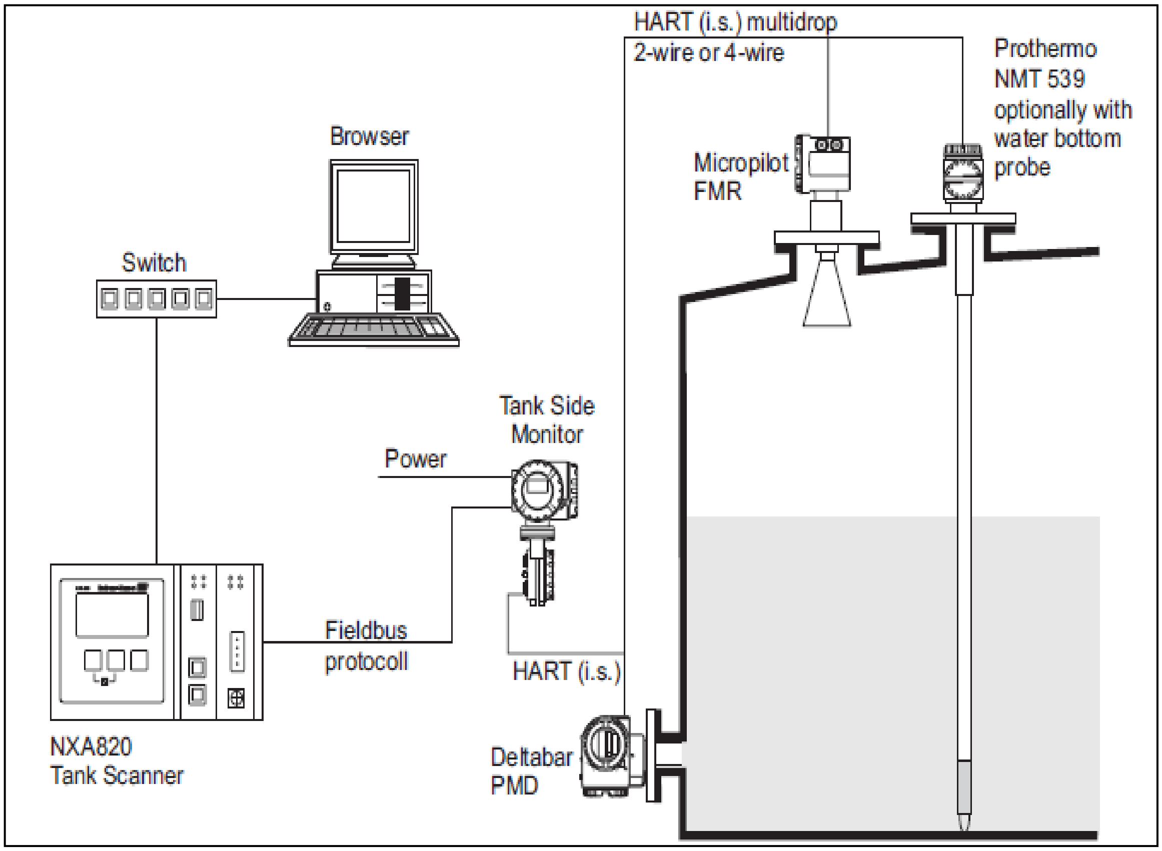

Figure 60 System integration[34]

3.3.2 Measuring the temperature of a liquid[51]

The temperature of the liquid in the tank is measured using thermometers. The temperature of a stored liquid may vary through its depth. Therefore, when measure the temperature, it is necessary to take several readings as recommended from API. The temperature of the tank measured at the middle of upper third part of the liquid and one in the middle of the liquid and the last one in the middle of the bottom of the liquid. There are two types of thermometer; portable and permanently mounted thermometer.

Portable Digital Thermometer- Option TS 13064

This thermometer can be used for custody transfer and storage tanks and trucks as shown in figure (61).

Figure 61 portable thermometer[51]

The product features

- Measurement range is -40°F to 325°F
- Accuracy is changing with temperature.

Permanently mounted thermometer

Some thermometer assemblies are permanently attached to the tank or vessel. Two types commonly used are the angle stem and dial type as shown in figure (62).

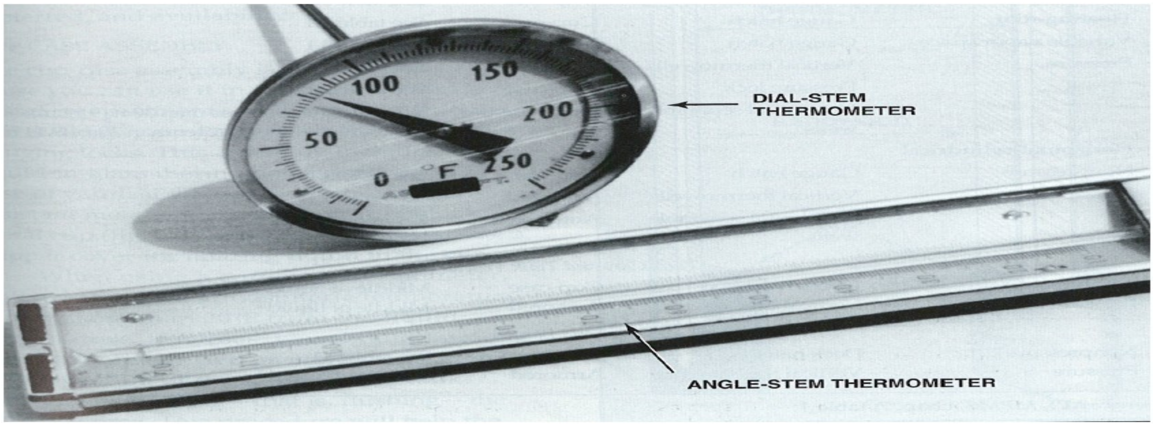

Figure 62 permanently mounted thermometer[51]

3.4 Natural gas transportation

Natural gas processing consists of separating all of the various hydrocarbons and fluids from the pure natural gas, to produce what is known as “pipe line quality “dry natural gas. Major transportation pipe lines usually impose restrictions on the composition of the natural gas that is allowed into the pipeline and measure energy content in KJ/KG (also called calorific value or Wobbe index).

The sales specification for natural gas usually involves[1]

1- Water dew –point- the temperature at which water will condense from the gas stream, which must be lower than any temperature likely to occur.
2- Hydrocarbon dew point the temperature at which liquid hydrocarbons will condense from the gas stream, which also must be lower than any temperature likely to occur.
3- Delivery pressure severely restricted maximum values of acid gas content-carbon dioxide and hydrogen sulfide- which are corrosive.

Gas transmission & distribution system loop

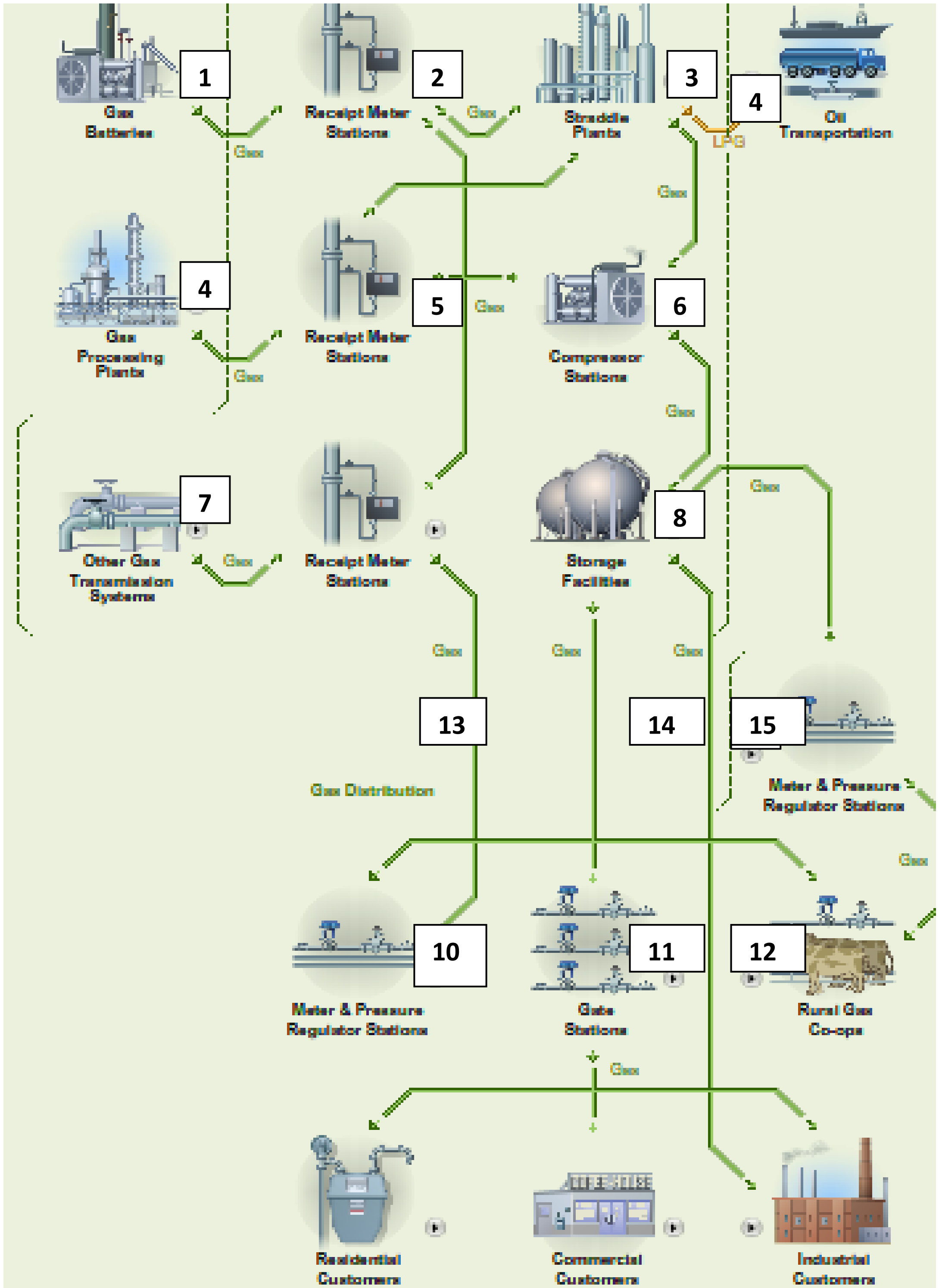

Figure 63 Gas transmissions and distribution cycle²

Definitions of gas transmissions and distribution cycle of fig (63):

1-Gas batteries: A system or arrangement of surface equipment that receives primarily gas from one or more wells prior to delivery to a gas gathering system, to market, or to other disposition. Gas batteries may include equipment for measurement and for separating inlet streams into gas, hydrocarbon liquid, and/or water phases. There are many occurrences of gas battery codes being assigned for the purpose of being a proration hub. In these instances there is no equipment onsite except a meter.

2-Receipt meter stations: A facility designed to regulate the flow rate and/or pressure of gas passing through a pipeline to a set level.

3-Straddle plants: A gas processing plant located on or in connection with a natural gas transmission line that removes residual natural gas liquids from the gas and returns the residue gas meeting commercial gas specifications to the transmission pipeline.

4-Oil transportation: The system for transport (by pipelines, tanker, truck or rail car) of crude oil and condensate from producing areas to upgraders and refineries.

5-Gas processing plants: Natural gas processing facility as shown in figure (64) is used for extracting from natural gas helium, nitrogen, ethane, or natural gas liquids, and/or the fractionation of mixed NGL to natural gas products. A natural gas processing plant may also include natural gas purification processes for upgrading the quality of the natural gas to be marketed to meet contract specifications (i.e., for removing contaminants such as water, $H2S$, $CO2$, and possibly adjusting the heating value by the addition or removal of nitrogen). The inlet natural gas may or may not have been processed through lease separators and field facilities.

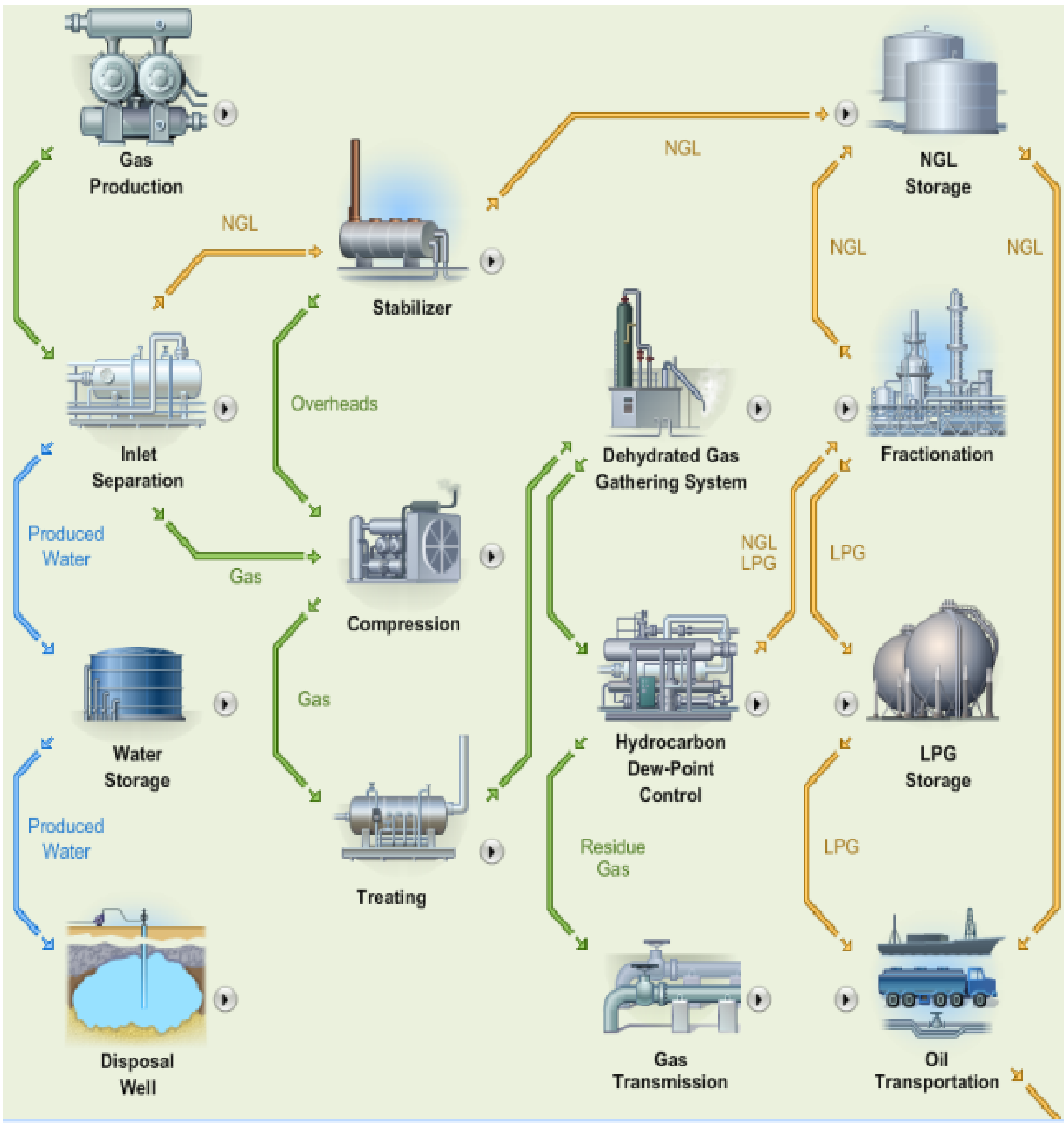

Figure 64 Gas processing diagram²

Gas processing cycle in figure (64) consists of:

- **Gas production**: Total natural gas output from oil and gas wells.
- **NGL storage**: A facility for storage of natural gas liquids (usually in aboveground atmospheric storage tanks often featuring floating roofs or a gas blanketing and vapor recovery system).
- **Stabilizers**: A heated pressure vessel or distillation tower used to boil off the volatile fraction of a liquid stream to produce a less volatile product suitable for storage in tanks at atmospheric pressure.
- **Inlet separation**: A vessel located at the entrance to a hydrocarbon facility that separates a multiphase incoming stream into different components, such as gas, oil or condensate and water.
- **Dehydration gas gathering system**: A device that through chemical and solid absorption processes regenerates the desiccant medium. Soft driers drain brine and are refilled with salt pellets.
- **Fractionation**: A gas fractional distillation process for separating natural gas and refinery/upgrader off-gases into their constituent boiling fractions to recover natural gas liquids: C2 (Ethane), or C3 (Propane), C4 (butanes) and C5 (pentane and higher boiling hydrocarbons, commonly referred to as natural gasoline).

- **Compression**: Service equipment intended to increase the flowing pressure of the gas that it receives from a well, battery, gathering system or transmission pipeline for delivery of natural gas to processing, storage or markets.
- **Water storage**: Tankage used to store produced water at oil and natural gas production, processing and transmission facilities prior to transportation to a disposal or re-injection facility.
- Hydrocarbon dew point control: A process for removing condensable hydrocarbons from natural gas to control the temperature at any given pressure at which liquid hydrocarbon initially condenses from a gas or vapor.
- **LPG storage**: A facility for storing liquefied petroleum gas (e.g., C2, C3 or C4). Typically, the LPG is stored in pressurized spherical or cylindrical steel tanks, but it may also be stored in caverns and various refrigerated containers.
- **Treating**: The application of processes to remove impurities from hydrocarbon streams such as water, carbon dioxide, hydrogen sulphide, and nitrogen.
- **Disposal well**: A well used for the disposal of any oilfield or processing waste fluids or produced water into a reservoir or non-portable water aquifer.
- **Gas transmission**: The transport (usually by cross-country pipelines) of natural gas at high pressure from producing areas to consuming areas.

- **Oil transportation**: The system for transport (by pipelines, tanker, truck or rail car) of crude oil and condensate from producing areas to upgraders and refineries.

6- Receipt meter stations: Defined in number two.

7-compressor stations: Service equipment intended to increase the flowing pressure of the gas that it receives from a well, battery, gathering system or transmission pipeline for delivery of natural gas to processing, storage or markets.

8-Other gas transmission systems: A cross county pipeline used to transport processed, normally unodourized natural gas to market (i.e., to gas distribution systems and major industrial customers). Most transmission pipelines also have some farm taps that provide gas to individual rural customers located along the pipeline in areas where service from distribution systems is not readily available. The pipelines are usually constructed of steel, although aluminum is used for some lower pressure applications (generally up to 3450 kPa or 500 psig). The pipe sizes range from 60.3 mm to 1219.2 mm O.D. (2 to 48 NPS), with the mid-range sizes most common. The operating pressures typically range from 1380 to over 6900 kPa (200 to 1000+ psig). The inlet natural gas may or may not have been processed through lease separators and field facilities.

9- Receipt meter stations: Defined in number two.

10- Storage facilities: Many transmission systems incorporate the use of storage in depleted gas reservoirs, caverns or spheres to help balance daily and seasonal variations in loads, and, therefore, are able to operate at steady capacity much of the time.

11-Mter and pressure regulator stations: A gas distribution facility for metering and reducing the pressure of gas being supplied to a local distribution network or major commercial or industrial customer.

12-Mter and pressure regulator stations: defined in number 11.

13-Gate stations: A station at which gas changes ownership and where gas is commonly odorized and flows through a splitter system for distribution to different districts or areas. The inlet gas is often metered, heated, and the pressure reduced. These stations may have multiple metering and pressure regulating runs.

14- Rural gas co-ops: A natural gas distribution system, owned by its members that delivers natural gas to rural customers by pipeline or other transport equipment.

15-Residential customers: Customer metering facilities for natural gas sales to residential customers. They include both pressure regulation and cumulative quantity measurement. The regulator typically reduces pressure from distribution pressure to a pressure appropriate for household appliances.

16- Residential customers: Customer metering facilities for natural gas sales to residential customers. They include both pressure regulation and cumulative quantity measurement. The regulator typically reduces pressure from distribution pressure to a pressure appropriate for household appliances.

17- Industrial customers: Metering facility that transfers gas from a distribution system to a large industrial customer. (Industrial customer being engaged primarily turning raw materials into finished products.) Typically, gas is supplied at intermediate or high pressure (400 to 3000 kPa [60 to 435 psig] or more), and is metered and pressure regulated.

3.5 Gas transportation measurements

Today, transport by gas pipeline is by far the most widespread method for transporting natural gas the main property that is measured is the flow rate which has always been an important part pf pipeline system operation. Measuring accuracy became much more important because of the petroleum price increase. The cost of inaccurate measurement and waste became so great that an investment sophisticated measurement equipment and the use of special techniques could be easily justified. Metering is done by flow meters which are given in details in chapter two. Accurate measurements is desirable, in the field the operator wants an accurate measurement of production from each well to help analyze well performance. Volume is not the only variable important in measuring hydrocarbons streams. The value of natural gas depends in part on its heat, or energy, content. Energy content is often expressed in British thermal units (BTU) per standard cubic foot (scf). A natural gas whose heat content is 900 BTU/SCF does not provide the consumer as much energy as one that has a heat content of 1000 BTU/SCF. Traditionally, gas purchase contracts specified only minimum BTU content, typically 100 BTU/SCF. As the value of natural gas increased in recent years, emphasis was placed on measurments techniques that more accurately reflect the energy value of the gas. In the United States, regulations require that measurement of natural gas reflect its BTU content.[50]The following table (6) is giving the natural gas specification

Table 6 Gas transport pipe line specification

Characteristic	**Value (Goar and Arrington, 1978)**
Water content	4-7 lb/MMscf max.
Hydrogen sulphide content	¼ grain/100 scf max.
Gross heating value	950 Btu/scf min.
Hydrocarbon dew point	15 °F @ 800 psig max.
Mercaptan content	0.2 grains/100 scf max.
Carbon dioxide content	1-3 mole percent max
Oxygen content	0 – 0.4 mole percent max.
Sand, dust and free liquid	Commercially free
Delivery temperature, °F	120°F max.
Delivery pressure, psia	700 psig min.

3.6 natural gas storage

Natural gas storage is necessary for the seasonal adjustment of consumption and gas supply, as demand for instance for heating is different in winter and in summer. The selection of the natural gas storage is shown in figure (65). It is used also for balancing daily and hourly fluctuations. In view of the large specific volume occupied by natural gas at ambient temperature and pressure, its storage is faced with the same difficulties as those encountered in transport. Two main storage methods are employed

1. **Cryogenic storage** in tanks, as LNG. If the gas does not arrive in this form, peak shaving liquefaction facilities must be available.
2. **Underground storage** in depleted reservoirs, aquifers or salt cavities.

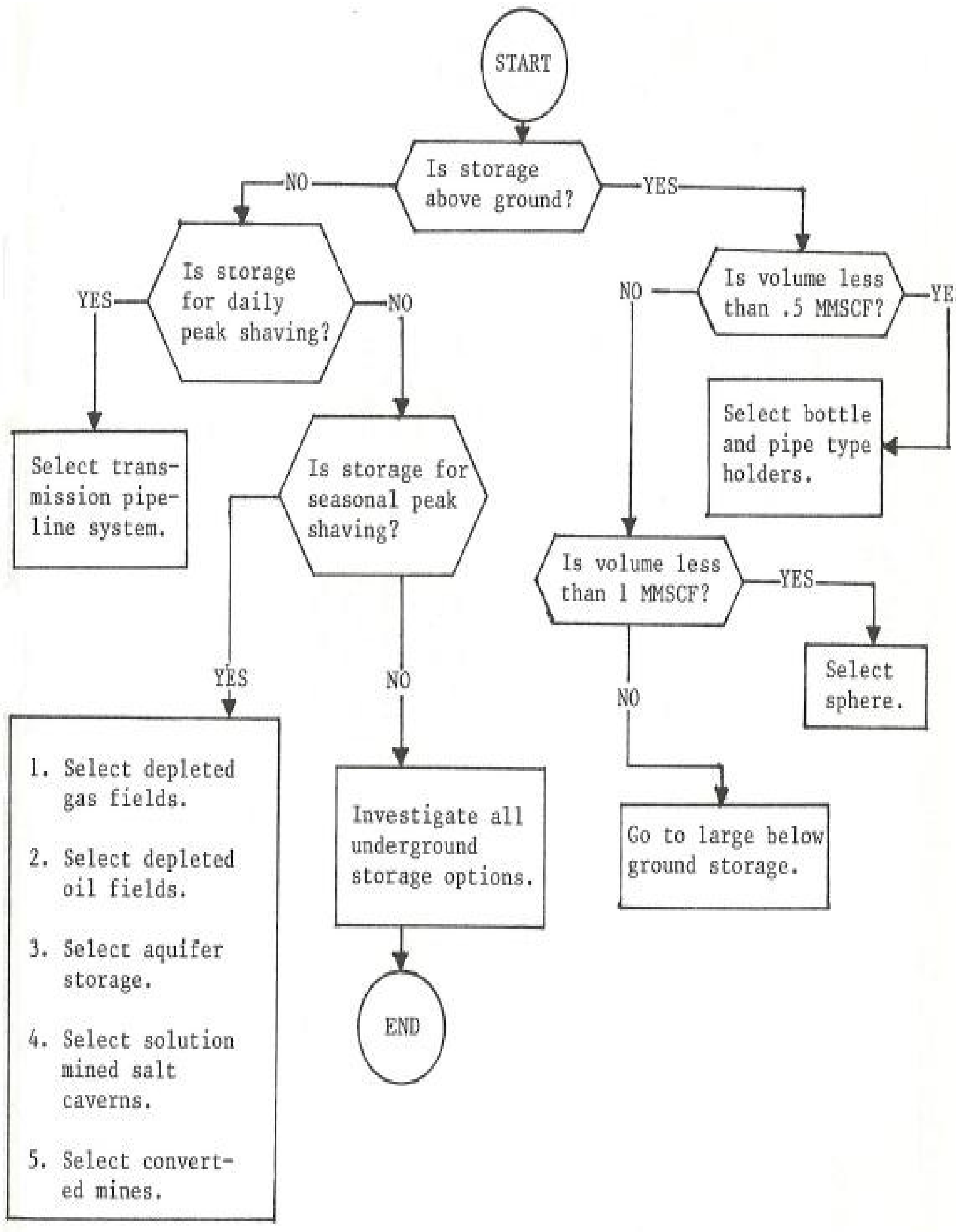

Figure 65 natural gas storage selection flow chart[47]

3.7 Storage gas measurements [47]

The most measurements done in the field collected in what's called Filed measurements check list. This list to have a check for the equipment and for measurements procedure as follows

1- Equipment
   - Measuring Tapes (Tank height, Tank Circumference, Tape Calibration)
   - Safety

2- Measurement Procedure
   - Measurement record form (Tank contents such as API gravity and average liquid temperature, Liquid head and temperature, etc.

Tank gauging is one of the important terms in the petroleum storage which defined as measuring, sampling and testing of crude oil to determine its quantity and quality. The principal activities related to gauging are as follows

3- Gauging- measuring the depth of the oil in the tank.
4- Recording tank temperature
5- Sampling and testing for API gravity and temperature
6- Sampling and testing for BS&W, that is basic sediment and water in suspension.

Chapter 4

4. Problems associated with the measurement

4.1 Introductions

This chapter is dividing the obstacles into the problems that the measurements devices may face and also highlighting the most subsequences of the production process begins. Additionally, referring to the field process facilities as one of the factors that influencing the production operations.

4.2 Measurement devices obstacles

4.2.1 Metering problems in general [20]

Experts claim that over 75 percent of the flow meters installed in industry are not performing satisfactorily. And improper selection accounts for 90 percent of these problems. Obviously, flow meter selection is no job for amateurs. The most important requirement knows exactly what the instrument is supposed to do. Here are some questions to consider. Is the measurement for process control (where repeatability is the major concern), or for accounting or custody transfer (where high accuracy is important)? Is local indication or a remote signal required? If a remote output is required, is it to be a proportional signal, or a contact closure to start or stop another device? Is the liquid viscous, clean, or slurry? Is it electrically conductive? What is its specific gravity or density? What flow rates are involved in the application? What are the processes' operating temperatures and pressures? Accuracy, range, linearity, repeatability, and piping requirements must also be considered. It is just as important to know what a flow meter cannot do as well as what it can do before a final selection is made. Each instrument has advantages and disadvantages, and the degree of performance satisfaction is directly related to how well an instrument's capabilities and shortcomings are matched to the application's requirements. Often, users have expectations of a flow meter's performance that are not consistent with what the supplier has provided. Most suppliers are anxious to help customers pick the right flow meter for a particular job.

Many provide questionnaires, checklists, and specification sheets designed to obtain the critical information necessary to match the correct flow meter to the job. Technological improvements of flow meters must be considered also. For example, a common mistake is to select a design that was most popular for a given application some years ago and to assume that it is still the best instrument for the job. Many changes and innovations may have occurred in recent years in the development of flow meters for that particular application, making the choice much broader .A recent development is the availability of computer programs to perform the tedious calculations often necessary for selecting flow meters. Calculations that used to take an hour can be performed in a matter of seconds. Production testing of individual wells for oil systems and many gas condensate systems is typically achieved by use of three phase separator vessels. Orifice meters are used to measure the gas stream and turbine meters are used to measure the water and liquid hydrocarbon streams. This equipment tends to be bulky and expensive, so it is often located at Production manifolds servicing several wells, each of which is individually tested through the vessel on a periodic basis. [21]Interpolation and extrapolation of successive test conditions is required to predict the production from wells based on wellhead and choke conditions when they are not going through the test separator for production accounting purposes. This method yields good results when production conditions, rates and fluid compositions are relatively stable, but is not reliable when well production rates change over a wide range due to processing equipment instability, or changing gas demand of the customer.

It may take several successive production tests using conventional testing methods to identify problems developing with specific wells. In addition, the potential for increased error in production accounting when using conventional well test procedures can have a significant effect on the accuracy of reservoir surveillance, modeling and production forecasting, particularly in complex reservoirs. [21]

Accuracy

Achieving consistent high accuracy measurements is the primary purpose. Custody Transfer measurement Facilities can achieve an accuracy of better than + 0.25%. Figure (66) show the measurement accuracy profile[48]. The ERCB has developed standards of accuracy for gas and liquid measurement that take into account such concerns as royalty, equity, reservoir engineering, declining production rates, and aging equipment. These standards have evolved, but originated from a 1972 Board hearing decision that determined a need for pool production accuracy standards of 2% for oil, 3% for gas, and 5% for water. The current standards are stated as “maximum uncertainty of monthly volume” and/or “single point measurement uncertainty.” The uncertainties are to be applied as “plus/minus” (e.g., ± 5%). Measurement at delivery/sales points must meet the highest accuracy standards because volumes determined at these points have a direct impact on royalty determination. Other measurement points that play a role in the overall accounting process are subject to less stringent accuracy standards to accommodate physical limitations and/or economics.[49]

With regard to accuracy, it is assumed an exact or true value exists for any variable that is valid for the conditions existing at the moment the result is determined. Determining the true value without doubt cannot be done, due to the limitations of measuring equipment and procedures and the possibility of human error. Typically, the closer one wants to approach the true value, the more expense and efforts have to be expended. Summary of standards of accuracy is given in appendix based on Energy Resources Conservation Board.

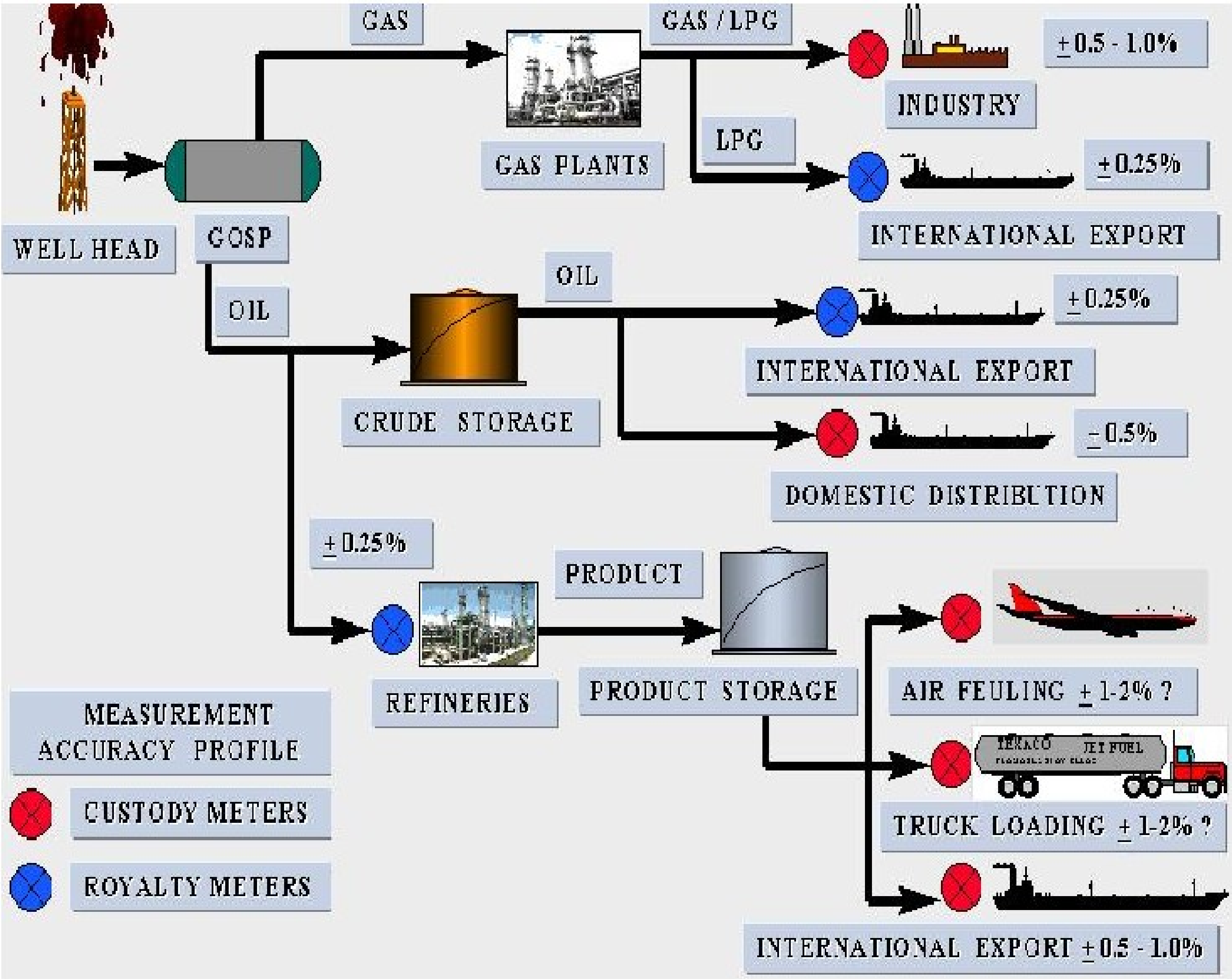

Figure 66 Measurement accuracy profile[48]

Measurement Precision

The primary purpose for better precision is to achieve and maintain proper accountability, insurance of flow measurement systems integrity and above all satisfaction between customer or client and supplier.

Proper Accountability

We cannot be held accountable for what we cannot measure. Proper accountability can be achieved by the application of proper control, effective monitoring and utilization of measurement procedures which are traceable to primary standards. This will ensure accurate design and correct installation of measurement facilities. The optimization of measurement systems and application of cost effective measurement equipment and technologies minimizes loss and provides more efficient operation of measurement facilities.

Working with flow meters

Although suppliers are always ready to provide flow meter installation service, estimates are that approximately 75 percent of the users install their own equipment. But installation mistakes are made. One of the most common is not allowing sufficient upstream and downstream straight-run piping for the flow meter. Every design has a certain amount of tolerance to non stable velocity conditions in the pipe, but all units require proper piping configurations to operate efficiently. Proper piping provides a normal flow pattern for the device. Without it, accuracy and performance are adversely affected. Flow meters are also installed backwards on occasion (especially true with orifice plates). Pressure-sensing lines may be reversed too. With electrical components, intrinsic safety is an important consideration in hazardous areas. Most flow meter suppliers offer intrinsically safe designs for such uses. Stray magnetic fields exist in most industrial plants. Power lines, relays, solenoids, transformers, motors, and generators all contribute their share of interference. Users must ensure themselves that the flow meter they have selected is immune to such interference. Problems occur primarily with the electronic components in secondary elements, which must be protected. Strict adherence to the manufacturers recommended installation practices will usually prevent such problems.

Calibration

All flow meters require an initial calibration. Most of the time, the instrument is calibrated by the manufacturer for the specified service conditions. However, if qualified personnel are available in the plant, the user can perform his calibrations. The need to recalibrate depends to a great extent on how well the meter fits the application. Some liquids passing through flow meters tend to be abrasive, erosive, or corrosive. In time, portions of the device will deteriorate sufficiently to affect performance. Some designs are more susceptible to damage than others. For example, wear of individual turbine blades will cause performance changes. If the application is critical, flow meter accuracy should be checked at frequent intervals. In other cases, recalibration may not be necessary for years because the application is noncritical, or nothing will change the meter's performance. Some flow meters require special equipment for calibration. Most manufacturers will provide such service in their plant or in the user's facility, where they will bring the equipment for on-site calibration.

Maintenance

A number of factors influence maintenance requirements and the life expectancy of flow meters. The major factor, of course, is matching the right instrument to the particular application. Poorly selected devices invariably will cause problems at an early date. Flow meters with no moving parts usually will require less attention than units with moving parts. But all flow meters eventually require some kind of maintenance. Primary elements in differential pressure flow meters require extensive piping, valves, and fittings when they are connected to their secondary elements, so maintenance may be a recurring effort in such installations. Impulse lines can plug or corrode and have to be cleaned or replaced. And, improper location of the secondary element can result in measurement errors. Relocating the element can be expensive. Flow meters with moving parts require periodic internal inspection, especially if the liquid being metered is dirty or viscous. Installing filters ahead of such units will help minimize fouling and wear. Obstructionless instruments, such as ultrasonic or electromagnetic meters, may develop problems with their secondary element's electronic components. Pressure sensors associated with secondary elements should be periodically removed and inspected.

Applications where coatings may occur are also potential problems for obstructionless instruments such as magnetic or ultrasonic units. If the coating is insulating, the operation of magnetic flow meters will ultimately be impaired if the electrodes are insulated from the liquid.

This condition will be prevented by periodic cleaning. With ultrasonic flow meters, refraction angles may change and the sonic energy absorbed by the coating will cause the meter to become inoperative.

Cost Considerations

There are a wide range of prices for flow meters. Rota meters are usually the least expensive, with some small-sized units available for less than $100. Mass flow meters cost the most. Prices start at about $3500. However, total system costs must always be considered when selecting flow meters. For example, an orifice plate may cost only about $50. But the transmitter may add an additional $500 or $600, and sensing line fabrication and installation may cost even more.

Installation, operation, and maintenance costs are important economic factors too. Servicing can be expensive on some of the more complicated designs. As with many other products, a plant engineer generally gets what he pays for when he purchases a flow meter. But the satisfaction that he receives with the product will depend on the care that he uses in selecting and installing the instrument. And that gets back to knowing the process, the products, and the flow-metering requirements. "Overbuying" is not uncommon. Plant engineers should not buy a flow meter more capable or complicated than they need.

4.3 Field process facilities influence[22]

In general, the total filed of production engineering can comprise in the following

- Reservoir performance; completion intervals, perforations performance, completion equipment.
- Well equipment; corrosion/erosion consideration, packer selection, safety valves, wire line services.
- Well performance analysis; natural flow performance, artificial lift equipments, performance analysis.
- Stimulation and remedial operations; acidizing, fracturing, recompletions.
- Oil and gas processing; separation, sweetening, dehydration.

The field process facilities necessary to meet sales or delivery specifications of hydrocarbon whether to the pipe lines or to the tankers and optimize the economic value of the hydrocarbon produced. Additionally, meet any statutory requirements for the disposal of ant part of the production. In some cases the objectives are easily met by very simple processing, but in other cases moderately sophisticated processing will be necessary particularly where delivery is to a tanker, so that a stable low pressure product must be delivered.

4.3.1 Gas processing[22]

All natural gases are produced saturated with water vapor, since they coexist in the reservoir at the reservoir temperature with the interstitial water in the reservoir. Also, nearly all natural gases contain small proportions of higher molecular weight hydrocarbons which will condense on reduction of temperature. Very reach condensate streams may produce more than 1000 m³ liquid condensate per million m³ of gas produced. Therefore, there are many processes must be done to treat the gas. There are many processes Such as gas sweetening, processing of dry natural gas and natural gas dehydration which will be discussed in more details.

4.3.1.1 Processing of dry natural gas - hydration formation

The first requirement, at the wellhead, is to take steps to remove water and water vapor before delivery to a pipe line. Water and hydrocarbons can combine together to form crystalline materials known as hydrate. These ice like crystalline materials are dependent upon both pressure and temperature, but are in general formed only at low temperatures (generally below 70°F). The expansion of gas through valves and fittings can cause such locally low temperatures, even when ambient temperatures are above hydrate formation temperatures. Short pipeline distances are not a problem, but longer distance may cause a multiphase well flow to separate and form severe slug- plugs of liquid with gas in between- traveling in the pipeline. Severe slugging may upset the separation process and cause overpressure safety shutdowns. Since a unified hydrate formation flow model does not exist, the problems will be described by breaking it into four end-member models

1- Oil-dominated system. These systems have gas, oil, and water, but are dominated by the presence of oil, in which all of the water is emulsified as droplets in the oil phase, either due to oil surfactants or shear. Here the oil hold up would typically be 50% (volume) or greater.

2- Gas-dominated systems. Gas-dominated systems have small amounts of liquid hydrocarbon or aqueous liquid present.
3- Gas condensate systems. These differ from oil-dominated systems in that they cannot disperse the water in the liquid hydrocarbon phase. Condensate systems are defined here to have water dissolved in the condensate, or suspended as droplets in the condensate due to high shear.
4- High-water-cut (volume) systems. When the water content is large (water hold up typically greater than 70% volume), such that water can no longer be totally emulsified in the oil phase, a separate continuous water phase exists. We limit.

The major reasons for dehydrating natural gas are:

- Natural gas can combine with liquid or free water to form solid hydrates that can plug valves, fittings or even pipelines.
- If not separated from the produced water, the number gas is corrosive, especially when CO_2 and/or H_2S are also present.
- Water can condense in the pipeline causing slug flow and possible erosion and corrosion..
- Water vaporincrease the volume and decrease the heating value of the gas.

- Sales gas contracts and/or pipeline specification have maximum water content -usually 7 lb H2O per MMscf.

Hydrate blockages in Oil-Dominated systems

The flowing figure (67) was generated by Tuner (2005) with input from J. Abrahamson (university of Canterbury, Christchurch, NZ), for hydrate formation in an oil dominated system with small (<50 volume %) water cuts.

In conceptual drawing in figure (67), four steps lead to hydrate plug formation along a flow line

1. Water is dispersed in an oil-continuous phase emulsion as droplets, typically less than 50μm diameter, due to oil chemistry and shear.

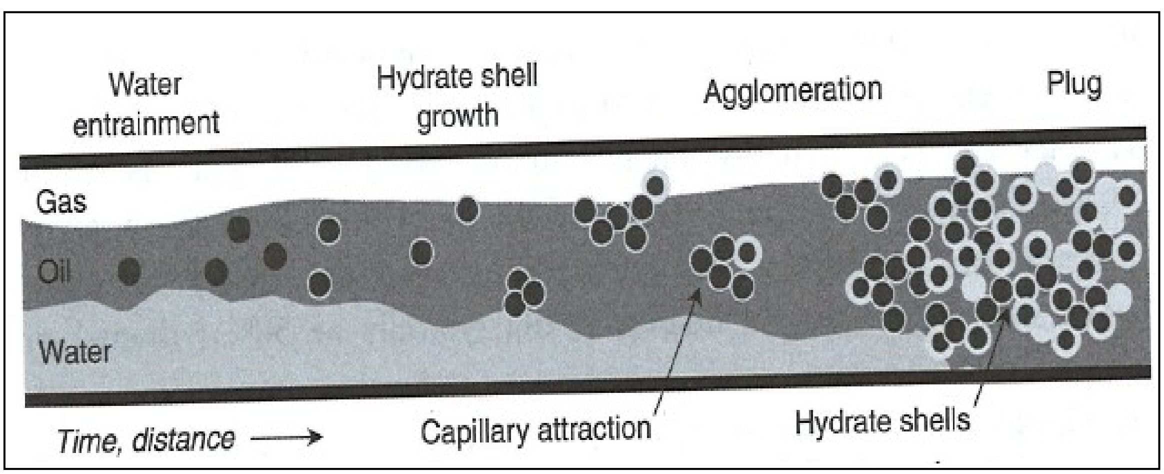

Figure 67 Hydrate formation in oil dominated oil[22]

2. As the flow line enters the hydrate formation region in figure (67) hydrate grows on the droplet rapidly (1mm/3 sec (Freer,

2000)) at the oil-water interface, forming thin (5-30 μm thick) hydrate shells around the droplets, with the particle size unchanged (Taylor er al., 2007).

3. Within each hydrate shell, shrinking-core droplets continue to grow, as a function of mass transfer of the guest and water through both the oil and the hydrate shell and heat transfer, dissipating the energy from hydrate formation. There may be free water within and between the droplets, which enables strong capillary attractive forces between the hydrate droplets.
4. Hydrate coated droplets will agglomerate to plug the pipeline, as shown in figure (67). This plug is initially mostly water, encapsulated within small hydrate crusts, although the plug acts like a solid and may continue to anneal to a more solid-like structure over time.

The key to preventing hydrate plug formation is to prevent agglomeration by cold slurry flow, anti-agglomerants, or other techniques such as in naturally inhibited oils.

Hydrate blockages in Gas-Dominated systems

Natural gas molecules smaller than n-butane can react with liquid or free water to form crystalline, snow-like solid solutions called hydrate. Hydrates have specific gravities ranging from 096 to 0.98 and therefore float on water and sink in liquid hydrocarbons. They are 90 weight percent water; the other 10 percent weight is composed of one or more of the following compounds; methane, ethane, propane, isobutane, n-butane, nitrogen, carbon dioxide, and hydrogen sulfide. Alone, n-butane does not form hydrates, but can contribute in a mixture. In solid hydrates the water or (host) molecules are linked together by hydrogen bonding into cage-like structures, called catharses that are stabilized by the inclusion of the natural-gas (guest) molecules. Smaller natural gas molecules (C1, C2, H2S, and CO2) form more-stable, body-centered cubic structures, while small quantities of larger molecules (C3, IC4) usually produce less-stable diamond lattices. Hydrate formation causes many operating problems, such as partial or complete blocking of gas gathering flow lines, fouling and blocking of heat exchangers, erosion of expanders.

The thermodynamic conditions promoting hydrate formation are

1. Presence of free or liquid water.
2. Low temperature and high pressure.

Hydrate formation is accelerated by agitation (such as high velocities or other turbulence), pressure pulsations, and a suitable site for crystal formation such as pipe elbows, orifice plates, thermo wells, scale, and solid corrosion products.

Prediction of Hydrate formation conditions[22]

The temperature and pressure at which hydrates form may be estimated by Katz’s gas gravity method, Katz’s equilibrium constant method, Baillie and Wichert’s chart for sour gases, and by equation-of-state approaches that require computer programs. These four methods are now summarized and compared by Sloan (1984) who assesses the gas-gravity, equilibrium-constant, and equation of state methods as follows

1- Gas gravity method should be considered a first-order estimate.
2- Katz el al. equilibrium-constant method represents a considerable improvement over the gas gravity method.
3- Equation of state (or computer) method is superior both in accuracy and ease of extrapolation.
4- Gas gravity method

Since this method was recommended in the comparison study therefore it will be discussed in this chapter. In Katz's (1954) gas-gravity method the temperature and/or pressure at which hydrates form is read directly from one graph figure (68). The natural gas is characterized by a single parameter- the specific gravity (or average molecular weight). While this method is very simple, description of a natural gas by a single parameter is approximate.

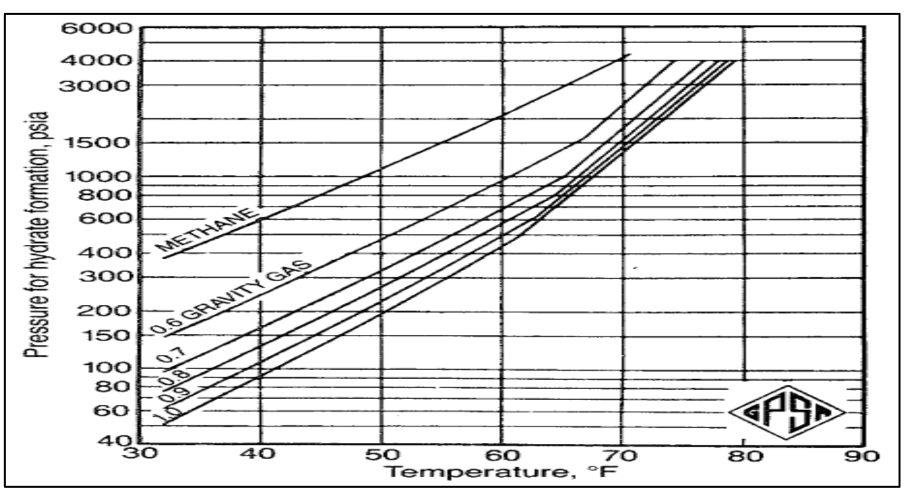

Figure 68 pressure- temperature curves for predicting hydrate formation[22]

Hydrate blockages in condensate flow lines

Some experiments study conclude that hydrates formed directly on the pipe wall will adhere to the wall, whereas hydrates formed in the bulk will not adhere to the wall. A conceptual picture shown in figure (69) for the hydrate formation in a condensate can be described with the following steps that correspond to the numbers in figure (69).

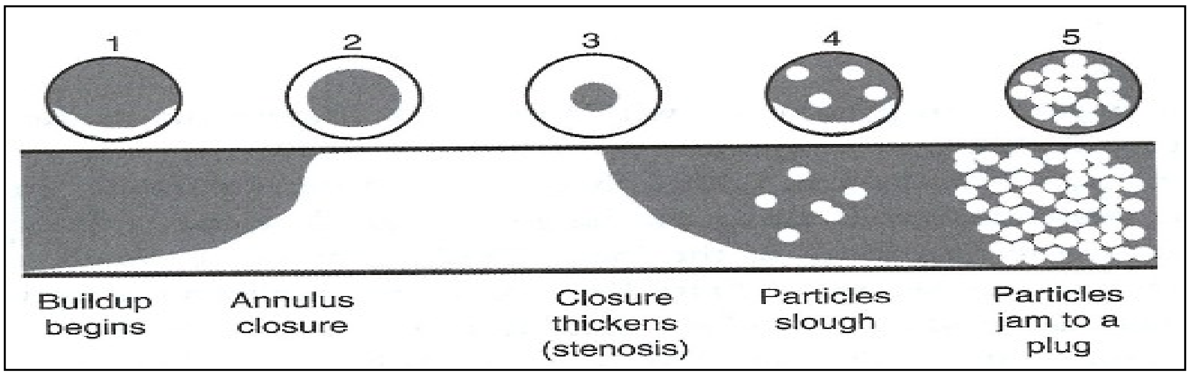

Figure 69 hydrate plugs form in condensate flow line[22]

1- Hydrate that begins to nucleate at the pipe surface will remain in the wall, dependent on water concentrations being higher than the hydrate stability limit in the condensate. This is usually caused by dehydrator malfunction resulting in high water content in the gas export line. High (>7 pound per million per day which is maximum allowable water vapor content) concentrations of dissolved water provide a uniform, dispersed deposit along the flow line.
2- After hydrate nucleate at the wall at point 1, they grow rapidly to encompass the entire circumference of the flow line.
3- As the hydrate continuo to grow, the effective diameter decreases analogous to arterio-stenosis in a blood vessel.

4- The large hydrate wall deposit builds until it is disturbed by some phenomenon, such as slug flow, density difference, harmonic resonance, and so on. At the point the deposit is no longer mechanically stable and sloughs from the pipe wall into the flow stream as hydrate particles.

5- The hydrate particles jam to a plug, preventing normal flow.

High water cut system

In systems with high water cuts, such as occur in later filed life, the water phase is not totally emulsified. A separate water phase occurs, as shown in the mechanism in figure (70). Upon on the continued addition of water, the water forms a separate phase. The inversion of the oil phase emulsion does not commonly occur, so that an external water phase remains.

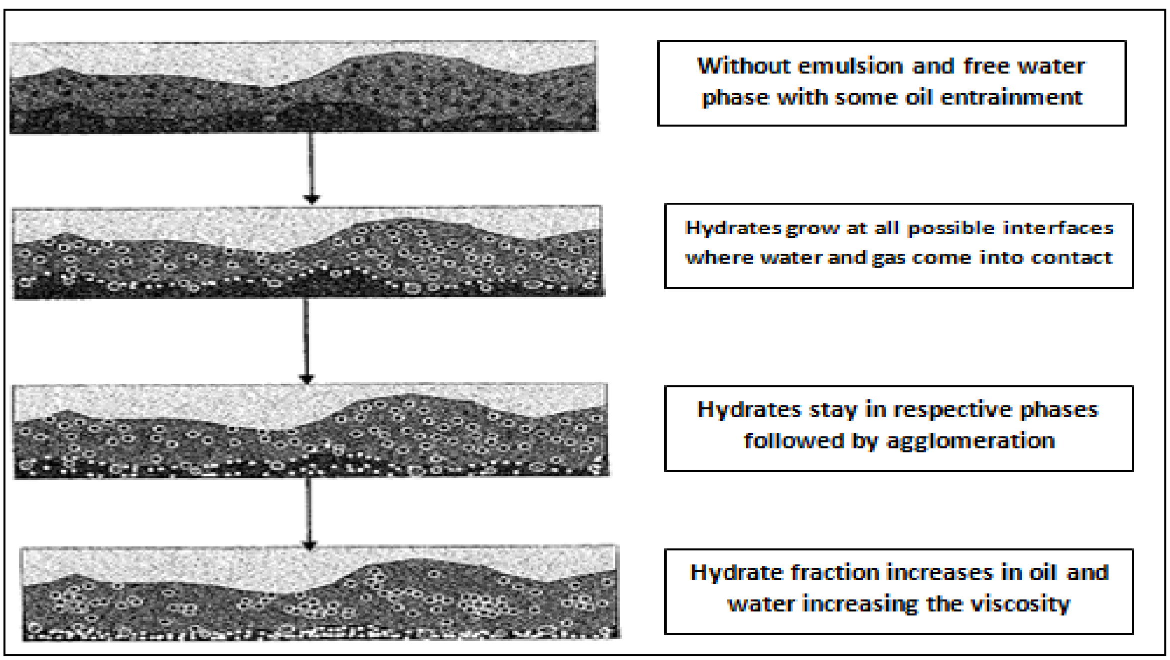

Figure 70 Hydrate formation in high water cut systems[22]

4.3.1.2 Blockage removal options[22]

The gases must be dried, heated or inhibited very near to the well head. There are essential four ways to remove hydrate blockage ;pressure reduction, chemical application, mechanical removal, and thermal application. Each has its merits and risks.

Pressure

Dissociation by reducing pressure below the dissociation pressure at ambient temperature is most widely used in industry. For any situation, compute the dissociation pressure for a given ambient temperature, and reduce the pressure evenly, if possible, on the plug. The lower the pressure achievable, the more rapidly the plug will melt. The goal of this method ultimately is to remove the plug. Once pressure communication has been established across the plug(s), it may then be possible to flood the system with thermodynamic inhibitor to accelerate the dissociation process, and stabilize the resultant mixture in preparation for cleanup operations. Or the onshore processing it is very important to meet dew point specification by a moderate cheap refrigeration process as shown in figure (71).

This diagram shows a typical process flow diagram where the intake gas is first chilled by heat exchange with the cool processed gas, glycol being added to inhibit hydrate formation. The gas then passes to a refrigeration unit where it is cooled to (-18 C°).

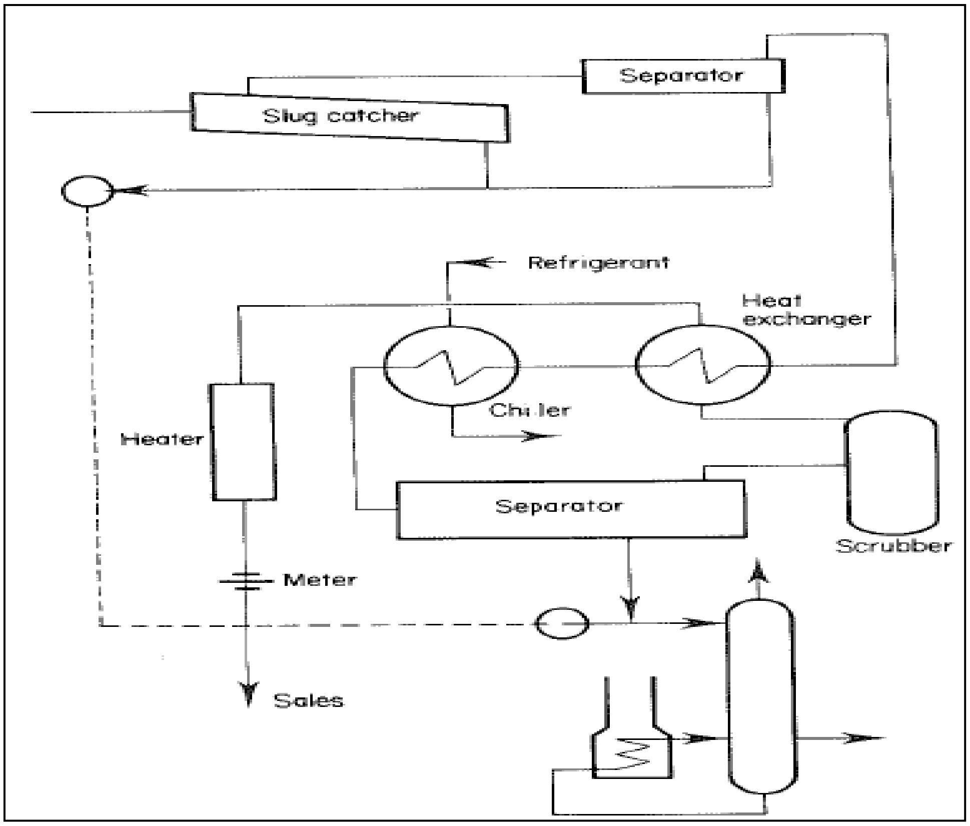

Figure 71 Refrigeration process of crude oil[22]

The resulting gas-liquid mixture is separated, the cool gas being heated first by heat exchange with incoming gas, and then by a fired heater before measurement and transfer. The liquids are boiled off to separate water, condensate and glycol. Liquids from slug catchers and knockouts are blended in, and the resulting stream stabilized to give a stable condensate fraction and a non-specification gas stream (which used for fuel). For subsea conditions (4C°) call for pressures around 200 to 130 lb/in², conditions that may not easily be reached because of hydrostatic head in subsea systems. It is important to know how fast the plug is going when it enters equipment, elbows, tees, valves, and so on. Clearly, plugs immediately adjacent to equipment and pipe fittings present the highest risk of damage. Presence of liquids filling the system adjacent to the downstream side of the plug can significantly attenuate plug velocity and should be considered in any analysis.

Chemical

It is difficult to get an inhibitor such as methanol or ethylene glycol next to a plug in a pipe line without an access method to the plug. Although plugs have been proven to be very porous and permeable, in gas systems a substation gas volume between the plug and injections points (platform and headlines) hinders contact, particularly when the line cannot be depressurized to encourage gas flow through the plug. Inhibitors must therefore displace other line fluids through density differences to reach plugs. Usually opportunity is greatest when the plug is close to production facilities or subsea manifolds or trees. In pipe lines with large variations in elevation, it is unlikely that an inhibitor will reach a plug without flow. Still, standard practice is to inject inhibitor next to a plug. Sometimes the increased density of heavy brines can provide a driving force to the hydrate plug face. Methanol or glycol injection is normally attempted first in a line. Density differences act as a driving force to get the inhibitor to the face of the plug, resulting in glycol being used more than methanol. Recent developments have shown that certain gases may also act as a solvent. Nitrogen and helium, for example, can easily permeate and dissociate hydrate plugs.

Mechanical

Coiled tubing has been used effectively where access is possible. This is especially for dry tree facilities. The well can be entered using standard lubricator designs with coiled tubing. The tubing is extended down the well until the plug is tagged. Pressure balance is maintained on either side of the plug, preventing sudden movement. Either methanol or hot water is jetted against the plug face, eroding and associating the plug.Hot water has been found to be very effective where heat transfer considerations prevent reforming of hydrates until the well fluids can be stabilized following removal of the plug and solid. The advantage of the hot water is safety concerns in handling fluids via temporary hoses on the facility. Methanol is highly volatile and requires special handling, procedures, personal protective.

Thermal

The basic concept of the thermal approach is to increase the temperature of the hydrate plug above the equilibrium point as shown in figure (72). As temperature is increased above the equilibrium conditions, gas is released from the melting hydrate plug. If the gas can easily escape, then the pressures near the hydrate plug will not significant increase. Note that in order for the gas to have a free path to escape, the entire length of the hydrate plug must be at the same temperature. If the entire length of the hydrate plug is not at the same temperature, gas may be trapped and creating localized high pressure.

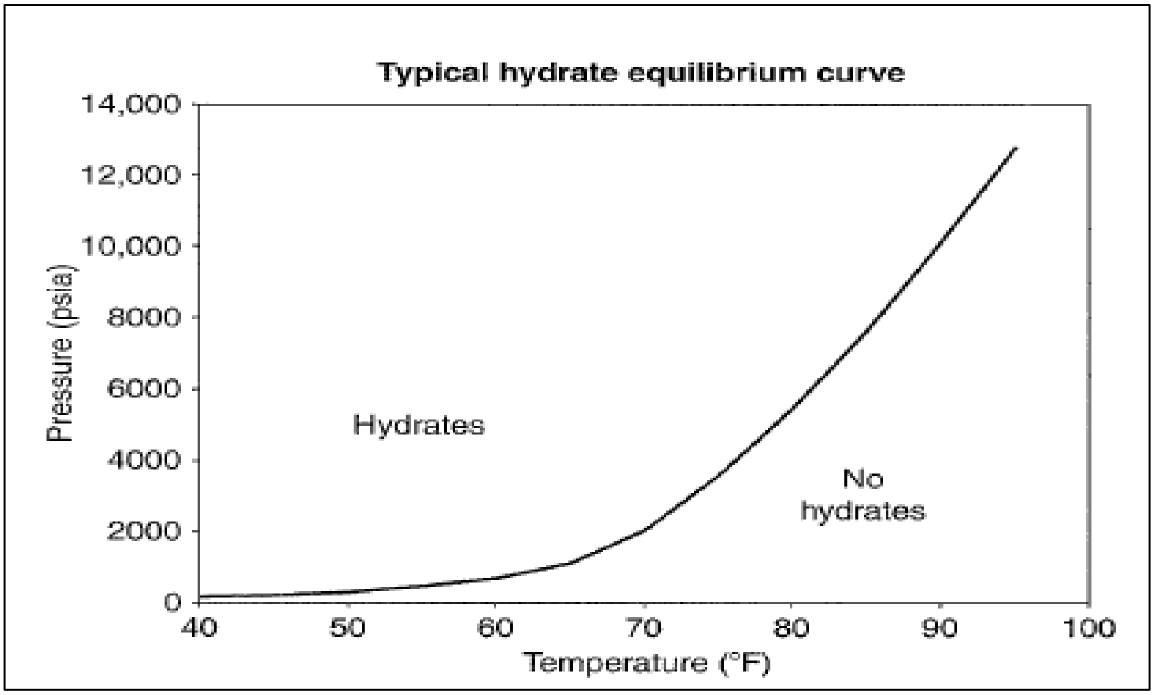

Figure 72 typical hydrate equilibrium curve showing increasing temperature[2]

When that happens, the pressure near the hydrate plug will increase until the hydrate equilibrium pressure is reached. Hydrates will then start reforming. If the temperature of the hydrate plug was raised to 85 °F in this example, and there was no free path available for gas to escape, pressures near the hydrate plug could reach 8000 Pisa. It is therefore imperative for any thermal method to have accurate temperature control.

4.3.2 Crude oil processing

There are many processes that can affect on the production resulted from the oil processing. For instance, the removal of salt which required meeting the refinery specification is one of the processes. This can be a problem when crude oil is produced with small proportion of water and first stage separation occurs at high temperatures. Under these conditions, the fresh water washing is the only necessary process, but this then involves further water separation. Therefore, optimization of a separator process design can yield a few extra percentage points of stabilized liquid and can make a difference of one or two degrees in the API gravity of the product. With a large oil flow this can be highly significant in cash flow terms.

4.3.2.1 Separation design consideration

Separators can be classified into two-phase and three-phase separators (commonly called free-water knockout) as shown in figure (73). The two-phase type deals only with oil and gas, while the three-phase type handles oil, water and gas. Additionally, separators can be categorized according to their operating pressure. Low-pressure units handle pressures of 10 to 180 psi [69 to 1241 kPa]. Medium-pressure separators operate from 230 to 700 psi [1586 to 4826 kPa]. High-pressure units handle pressures of 975 to 1500 psi [6722 to 10,342 kPa].[26]Gravity segregation is the main force that accomplishes the separation, which means the heaviest fluid settles to the bottom and the lightest fluid rises to the top. Additionally, inside the vessel, the degree of separation between gas and liquid will depend on the separator operating pressure, the residence time (called retention time or residence time) of the fluid mixture and the type of flow of the fluid. Turbulent flow allows more bubbles to escape than laminar flow. The retention time defined as the amount of time a liquid stays in a vessel. The retention time assures that equilibrium between the liquid and gas has been reached at separator pressure.

The important factor of separator design is the retention time in a separator which is determined by dividing the liquid volume inside the vessel by the liquid flow rate. The retention time usually varies between 30 seconds and 3 minutes. If foaming crude is present, the retention time could be increased by four times its normal values.

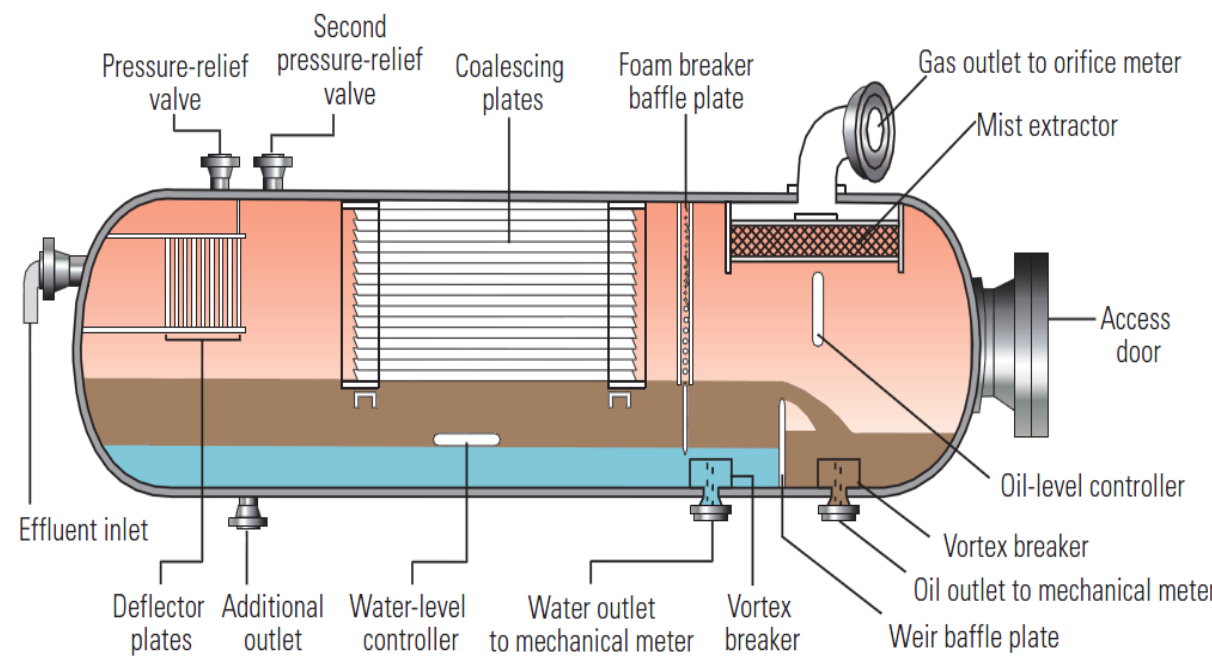

Figure 73 Three phase separator[26]

The gas phase may pass through a Coalescer in which liquid droplets impinge, coalesce and drip back into the liquid phase. After the Coalescer, the gas passes through a demister section (A pad of weir mesh), further to entrap and coalesce entrained liquid droplets. In the gas region separator, gas velocity is the critical design factor, and the maximum gas velocity expressed as in equation number (10). Level controls, and level warnings and shut down systems will keep the separator working within its design limit. With multi stages of separation, the pressures and temperatures of each stage of separation are important to the efficiency of separation as shown in figure (74).

$$V = C\,((\rho o-\rho g)/\,\rho g)^{\wedge}0.5 \qquad (10)$$

Whereas

V= critical entrainment velocity (ft/s).

C= separator coefficient (0.35-0.05 ft/s).

Po-ρg = oil and gas densities respectively kg/m³.

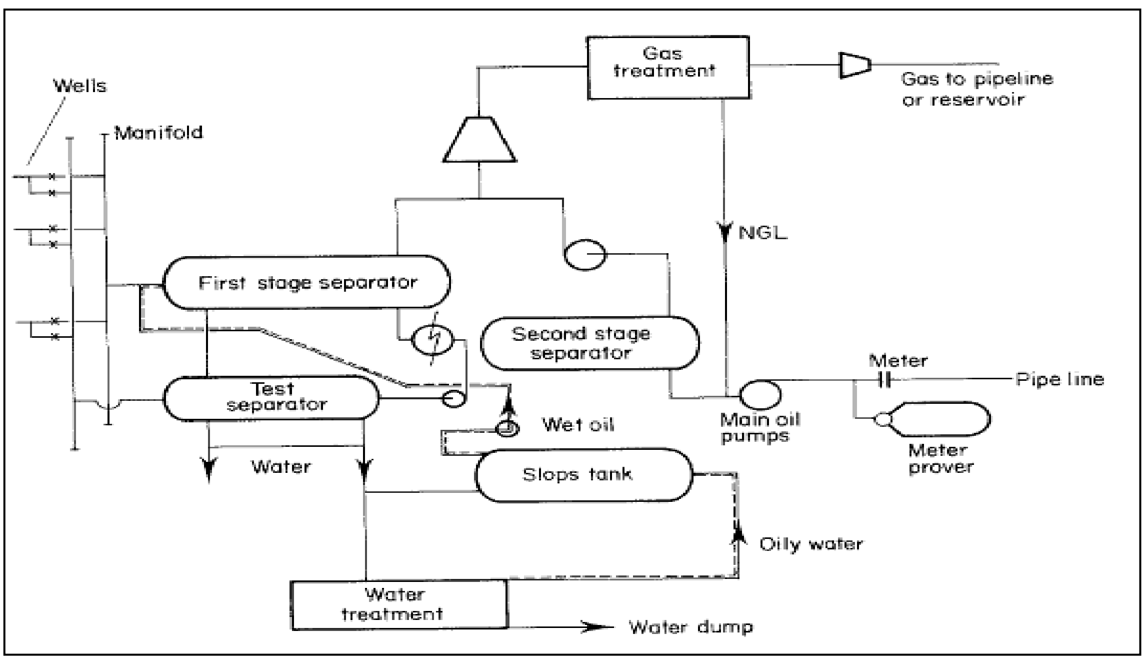

Figure 74 multistage separator[24]

4.3.2.2 Foaming problems[24]

With light gassy crude oils, a separation problem can occur if foams form with flow restrictions of a typical separation system, In this case, the residence times necessary for foams to drain effectively and break can be prohibitive and separation highly inefficient. The most effective remedy is chemical foam breaking, the addition of a silicone liquid upstream of the separation .The most effective remedy is chemical foam breaking, the addition of a silicone liquid upstream of the separators being highly effective in promoting foam drainage and break down. Foaming can cause poor efficiency, reduced throughput, as well as loss of expensive absorbent by carry over.

4.3.2.3 Sand

Sand can be very troublesome in separators by causing cutout of value trim, plugging of separator internals, and accumulation in the bottom of the separator. Special hard trim can minimize effects of sand on the valves. Accumulations of sand can be alleviated by the use of sand jets and drains.

Plugging of separator internals is a problem that must be considered in the design of the separator. A design that will promote good separation and have a minimum of traps for sand accumulation may be difficult to attain, since the design that provides the best mechanism for separating the gas, oil, and water phases probably will also provides areas for sand accumulation. A practical balance for these factors is best solution.

Chapter 5

5. Future trends of the oil industry methodology and development update

5.1 Introductions

Most of the technology required in the coming years will not be revolutionary, but the need for innovative approaches to lower cost and higher efficiency has never been greater.

5.2 Recent Developments and markets metering requirements

The future looks bright for flow meters as flow measurements characterized by the continuous development of new and improved techniques. Although the global recession over the last two years took its toll on the flow meter market, the research company sees a strong future for the world flow meter market. New research study finds that the world wide flow meter market totaled U.S. $ 4.6 Billion in 2009 and is projected to grow substantially to exceed to $5.5 Billion in 2014 as illustrated in figure (75). The market is benefitting from the drive for new energy sources, including the search for more oil and gas, as well as increasing renewable energy development. The market is also continuing its shift from traditional flow meters to new technology flow meters at a rate that exceeds one percent a year. Increased concerns with accuracy and reliability in measurement could accelerate the trend. While the new technology flow meters are displacing traditional technology meters in some applications, it is clear that traditional meters are still a major force in the flow meter market traditional meters, especially including DP flow, positive displacement, and turbine meters, have the advantage of having a large installed base.

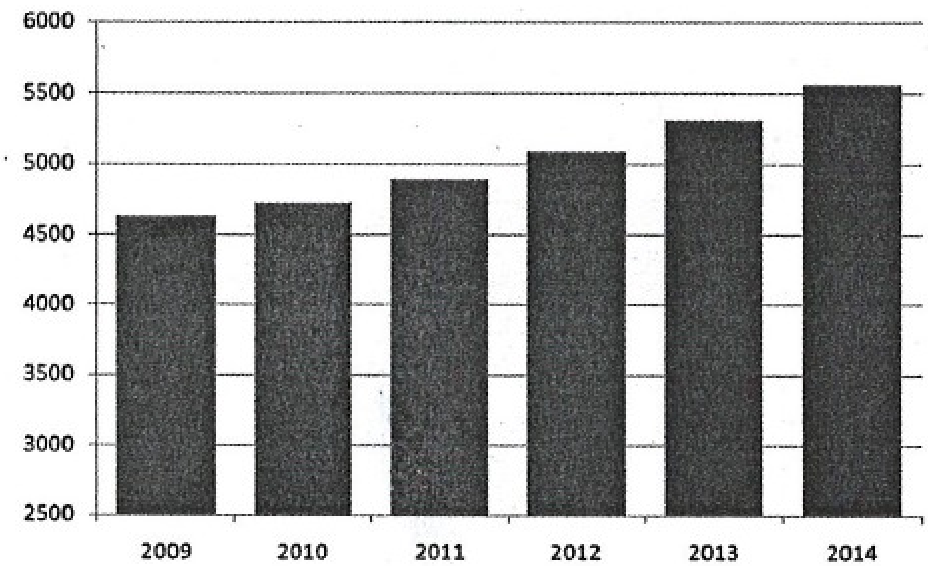

Figure 75 Total shipments of all flow meters worldwide[4] [6] (MM$)

In addition, they were among the first types of flow meters to received approvals from industry applications. While many new technology flow meters have also received these approvals changeover that is occurring to these new-technology meters is taking time. Some end-users prefer to stick with an existing and known technology. Coriolis and ultrasonic flow meters are projected to have the fastest growth rates throughout the forecast period. Despite the large installed base of traditional technology flow meters, user requirements for increased accuracy and reliability are causing end users to make the switch to new technology meters in some cases. Figure (76) shows the boom in the Ultrasonic flow meters. Coriolis and ultra sonic flow meters have also received industry association approvals for custody transfer of both gas and liquids, and this is having an influence on the markets. Vortex flow meters have also received approval for custody transfer applications from the American petroleum institute in 2007. With crude oil selling in the $100 per barrel range, measurement accuracy and reliability are becoming increasingly important. Ultrasonic and Coriolis flow meters for custody transfer measurement are two of the fastest growing segments.[46]

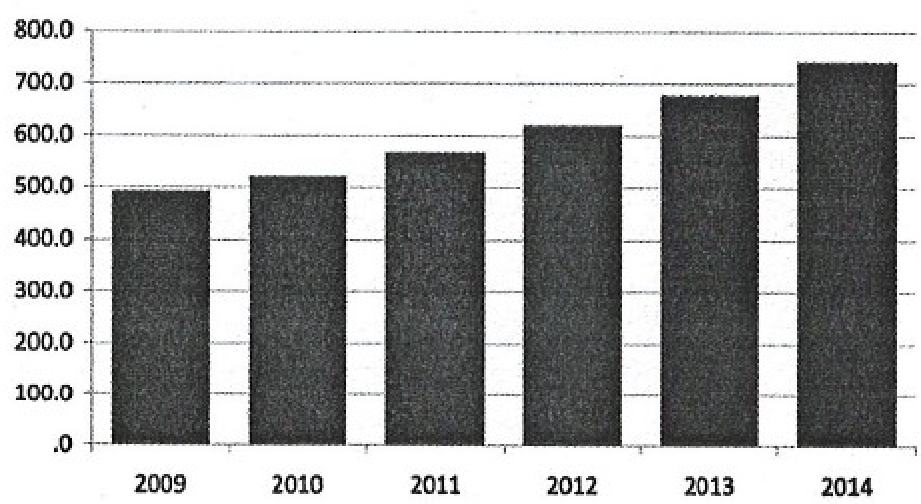

Figure 76 the growth in ultrasonic shipments worldwide[46]

5.2.1 Vortex meters

Smart vortex meters provide a digital output signal containing more information than just flow rate. The microprocessor in the flow meter can automatically correct for insufficient straight pipe conditions, for differences between the bore diameter and that of the mating pipe, for thermal expansion of the bluff body, and for K-factor changes when the Reynolds number drops below 10,000.

Intelligent transmitters are also provided with diagnostic subroutines to signal component or other failures. Smart transmitters can initiate testing routines to identify problems with both the meter and with the application. These on-demand tests can also assist in ISO 9000 verification. Some recently introduced vortex flow meters can detect mass flow. One such design measures both the vortex frequency and the vortex pulse strength simultaneously. From these readings, the density of the process fluid can be determined and the mass flow calculated to within 2% of span.

Another newer design is provided with multiple sensors to detect not only the vortex frequency, but also the temperature and pressure of the process fluid. Based on that data, it determines both the density and the mass flow rate. This meter offers a 1.25% of rate accuracy when measuring the mass flow of liquids and a 2% of rate accuracy for gases and steam. If knowledge of process pressure and temperature is of value for other reasons, this meter provides a convenient, less costly alternative to installing separate transmitters.

5.2.2 Multiphase flow meters[25]

A forecast based on the trends in sales and installations worldwide indicates that the upstream industry will install many multiphase flow meters during next 5-10 years. Multi phase flow meters MFMs offer many claimed capabilities but vendors still face the problems of the slow uptake of MFMs technology by the oil and gas industry to entry into this market. Later study claimed the perception that MFM is a mature technology is misplaced because its impact is just beginning to be felt with an estimated market penetration of only 0.3% .This would amount to 3000 meters for 1 million producing wells worldwide.

MFM applications are diverse, ranging from onshore to offshore, from new development projects to retrofits of declining fields, and from wet gas to heavy oil streams. Figure (77) lists the currently available MFMs in the market along with their key technical characteristics claimed by their manufactures. MFMs history suggests that a universal metering solution does not exist. Operators often claim poor correlation between performance and innovation as the reason for their not being more proactive in adopting new technology. A recent study predicts that companies will deploy 1000 additional subsea MFMs by 2015. However, future growth in the MFM market could include new meters for monitoring injected supercritical CO2 in carbon capture and underground projects.

Operators have ranked highly clamp-on meters in their wish list because these meters have a negligible effect on an existing facility's layout and, for subsea applications, one could attach these meters onto seabed flow lines with remotely operated vehicles. Unfortunately, relatively few researchers have proposed such meters to date, given the technical challenges of measuring flow through the pipe wall, but it is hoped that future research will address this application.

Barriers to technology development

- Weak understanding of strategic rationale for being technology leader.
- Lack of stability in funding
- Lack of patent protection

- Organizational conservation and risk-averse approach to technology decisions.
- Insufficient cooperation with technology suppliers

	Gas volume fraction, %	Downhole MFM	Venturi/cone	Flow conditioning/ homogenization	Isokinetic sampling	Tracer	X-correlation	In-line separation	Radioactive source
Abbon Acoustic flowmeter	0-99.8		■						
Abbon Optimum C400	0-90			■					
Accuflow	0-99							■	
Agar MPFM 300	0-97		■	■					
Agar MPFM 400 loop	0-99.6		■	■				■	
Agar MPFM 50	0-100								
ESMER	0-100		■						
ESMER Mobile	0-100		■						
ESMER Wet gas	95-100		■						
Expro Petrotech SmartVent MultiTrace	90-100		■			■			
GLCC (Tulsa) Multiphase metering loop	-							■	
Pietro Fiorentini Flowatch	0-97		■				■		
Pietro Fiorentini Flowatch High GVF	0-99		■				■	■	
Haimo MPFM	0-99.8		■	■				■	■
Hydralift Wellcomp								■	
Jiskoot (Cameron) MIXMETER	0-90			■					■
Kvaerner Duet	0-99						■		■
Kvaerner Duet with Venturi	97-100		■				■		■
McCrometer V-Cone and Wafer Cone			■						
Neftemer									■
PhaseDynamics Kvaerner CCM	0-100							■	
QuantX		■							
Red Eye REMMS Weatherford	0-95							■	
Roxar (Emerson) MPFM 2600	0-95		■						
Roxar (Emerson) MPFM 2600 with gamma	0-100		■						■
Roxar (Emerson) MPFM WGM95	0-100		■						
Schlumberger PhaseTester			■						■
Schlumberger PhaseWatcher oil mode	0-98		■						■
Schlumberger PhaseWatcher gas mode	90-100		■						■
Solartron Ametek Dualstream I	95-100		■						
Solartron Ametek Dualstream I advanced	98-100		■						
Solarton Ametek Dualstream II advanced	80-100		■						
TEA Sistemi Lyra	0-90		■						■
TEA Sistemi Vega	90-100				■			■	
CiDRA Weatherford		■							
CiDRA SONARtrac									

Figure 77 commercial manufactures[25]

6. Conclusion

- Crude and hydrocarbon measurement technologies serve to control and minimize hydrocarbon losses by providing accurate measurement and proper accountability and reduce measurement errors to 0.25% of instrument readings by application of current state of the art measurement technologies.
- The nature of the well stream has an impact on the surface facility design, including reservoir drive, the water oil ratio(WOR), the gas oil ratio (GOR) or alternatively the gas liquid ratio(GLR), and the of the crude oil (°API, Pour point, etc).
- The scope of processing depends on the nature of the well fluids and Both streams of oil and gas may require further processing before sales such as removal of hydrogen sulfide and water. The oil may require emulsion treating and/or desalting.
- An understanding of the process (operating and fluid) conditions, as well as, the physical properties of the hydrocarbon fluids is fundamentally important before designing or analyzing production facilities and needed for reservoir management.
- There are a certain properties must be measured for petroleum fluids to be used in further calculation as well as to meet the required sales specifications, besides Provide effective monitoring and application of measurement and loss control

standards to measurement facilities for compliance and quality assurance

- The measurments of the petroleum fluids is necessary for assure the safety of the location by measuring a certain properties which are needed to monitoring the production operation and these measurements can be used in predicting problems before happening.
- Some measurements are carried out in the laboratory and some are carried in the field as required by the stage whether in transport or in the storage stage.
- There are problems associated to some of the processes and some obstacles resulted from the process that affects the measurements accuracy.
- Accurate measurement of hydrocarbon fluids has a high impact on the Gross National Product of exporting and importing countries, the financial performance and asset base of global companies, and the perceived efficiency of operating facilities.
- Future trend in the measurements devices will be concentrating in the improving the measurements accuracy and instruments efficiency rather than inventing new ones to have specific objectives in a cost-effective manner.

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APPENDIX

TABLE (1) FLOW METER EVALUATION TABLE [8]

Table 1: Flowmeter Evaluation Table

FLOWMETER	PIPE SIZE, in. (mm)	STEAM	GASES (VAPORS) CLEAN	GASES (VAPORS) DIRTY	LIQUIDS PRESS HIGH	LIQUIDS PRESS LOW	LIQUIDS CLEAN	LIQUIDS VISCOUS HIGH	LIQUIDS VISCOUS LOW	LIQUIDS DIRTY	LIQUIDS CORROSIVE	LIQUIDS VERY CORROSIVE	LIQUIDS SLURRIES FIBROUS	LIQUIDS SLURRIES ABRASIVE	REVERSE FLOW	PULSATING FLOW	HIGH TEMPERATURE	CRYOGENIC	SEMI-FILLED PIPES	NON-NEWTONIANS	OPEN CHANNEL	TYPICAL Accuracy, uncalibrated (Including transmitter)	TYPICAL Reynolds number ‡ or viscosity	TEMPERATURE °F (°C)	PRESSURE psig (kPa)
SQUARE ROOT SCALE: MAXIMUM SINGLE RANGE 4:1 (Typical)**																									
Orifice																								Process temperature to 1000°F (540°C); Transmitter limited to -30-250°F (-30-120°C)	To 4,000 psig (41,000 kPa)
Square-Edged	>1.5 (40)	√	√	X	√	√	√	X	?	X	?	X	X	X	SD	?	√	√	X	?	X	−1-4% URV	R_D > 10,000		
Honed Meter Run	0.5-1.5 (12-40)	√	√	X	√	√	√	?	?	X	?	X	X	X	SD	?	√	√	X	?	X	−1% URV	R_D > 10,000		
Integrated	<0.5 (12)	?	√	X	√	√	√	X	?	X	?	?	X	X	SD	?	?	X	X	?	X	−2-5% URV	R_D > 10,000		
Segmental Wedge	<12 (300)	√	√	√	√	√	√	?	√	?	?	X	?	?	SD	?	√	√	X	?	X	−0.5% URV	R_D > 500		
Eccentric	>2 (50)	?	?	√	√	√	?	X	?	?	?	X	?	X	SD	?	√	√	X	?	X	−2-4% URV	R_D > 10,000		
Segmental	>4 (100)	?	?	√	√	√	?	X	?	?	?	X	?	X	SD	?	√	√	X	?	X	−2-4% URV	R_D > 10,000		
V-Cone	0.5-72 (12-1800)	√	√	?	√	√	√	?	√	?	?	X	?	?	X	?	?	?	X	?	X	−0.5-1% of rate	R_D : 8,000-5,000,000	700 (370)	±600 (4,100)
Target***	<0.5(12)	?	√	√	√	√	√	?	√	√	?	X	X	X	?	X	?	?	X	?	X	−0.5-5% URV	R_D > 100	Process temperature to 1000°F (540°C); Transmitter limited to -30-250°F (-30-120°C)	To 4,000 psig (41,000 kPa)
Venturi	>2 (50)	√	√	?	√	√	√	?	√	?	?	X	√	?	X	?	?	?	X	?	X	−0.5-2% URV	R_D > 75,000Ł		
Flow Nozzle	>2 (50)	?	√	?	√	√	√	X	?	?	?	X	X	X	X	?	?	?	X	?	X	−1-2% URV	R_D > 50,000Ł		
Low Loss Venturi	>3 (75)	√	√	X	√	√	√	X	?	X	√	X	X	X	X	?	?	?	X	?	X	−1.25% URV	R_D > 12,800Ł		
Pitot	>3 (75)	X	√	X	√	√	√	X	?	X	?	X	X	X	X	X	?	?	X	X	X	−3-5% URV	R_D > 100,000Ł		
Averaging Pitot	>1 (25)	√	√	SD	√	√	√	X	?	SD	?	X	X	X	SD	X	?	?	X	X	X	−1-2% URV	R_D > 40,000Ł		
Elbow	>2 (50)	X	√	?	√	√	√	X	?	?	?	X	X	X	√	X	?	?	X	?	X	−5-10% URV	R_D > 10,000Ł		
Laminar	0.25-16.6 (6-400)	?	√	X	√	√	√	√	?	X	?	X	X	X	X	√	X	X	X	X	X	−1% of rate	R_D < 500	150 (66)	±30 (225)
LINEAR SCALE TYPICAL RANGE 10:1 (Or better)																									
Magnetic*	0.1-72 (2.5-1800)	X	X	X	X	X	√	?	√	√	√	√	√	√	√	√	?	X	?	?	?	−0.5% of rate	R_D > 4,500	360 (180)	≤1,500 (10,800)
Positive Displacement																									
Gas	<12 (300)	X	√	X	?	√	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	−1% of rate	-	250 (120)	≤1,400 (10,000)
Liquid	<12 (300)	X	X	X	X	X	√	√	?	X	?	X	X	X	X	X	?	X	X	X	X	−0.5% of rate	No R_D limit ≤ 8,000 cS	600 (315)	≤1,400 (10,000)
Turbine																									
Gas	0.25-24 (6-600)	SD	√	X	√	√	X	X	X	X	X	X	X	X	SD	SD	?	?	X	X	?	−0.5% of rate	-	-450-500 (268-260)	≤3,000 (21,000)
Liquid	0.25-24 (6-600)	X	X	X	X	X	√	X	?	X	?	X	X	SD	SD	SD	?	?	X	X	?	−0.5% of rate	R_D > 5,000, ≤15 cS	-450-500 (268-260)	≤3,000 (21,000)
Ultrasonic																									
Time of Flight	>0.5 (12)	X	SD	SD	SD	SD	√	?	?	X	√	√	?	?	√	√	X	?	X	X	?	−1% of rate to ffl5% URV	R_D > 10,000	-300-500 (-180-260)	Pipe rating
Doppler	>0.5 (12)	X	X	X	X	X	X	?	?	√	√	√	√	√	√	√	X	X	X	?	X	−1% of rate to ffl5% URV	R_D > 4,000	-300-500 (-180-260)	Pipe rating
Variable-Area (Rotameter)	≤3 (75)	?	√	X	X	√	√	X	?	X	?	?	X	X	X	?	?	?	X	X	X	−1% of rate to ffl10% URV	No R_D limit, < 100 cS	Glass: 400 (200) Metal: 1,000 (540)	Glass: 350 (2,400) Metal: 720 (5,000)
Vortex Shedding	1.5-16 (40-400)	√	√	?	√	√	√	X	?	?	?	X	X	X	X	X	?	?	X	X	X	−0.75-1.5% of rate	R_D > 10,000, < 30 cP	400 (200)	≤1,500 (10,500)
Vortex Precession (Swirl)	<16 (400)	√	√	?	√	√	√	X	?	X	?	X	X	X	X	X	?	X	X	X	X	−0.5% of rate	R_D > 10,000, < 5 cP	536 (280)	Pipe rating
Fluidic Oscillation (Coanda)	>1.5 (40)	X	X	X	X	X	√	X	X	?	?	X	X	X	X	?	?	?	X	X	X	−2% of rate	R_D > 2,000, < 80 cS	350 (175)	≤720 (5,000)
Mass																									
Coriolis	0.25-6 (6-150)	?	?	?	√	√	√	√	√	√	?	?	?	√	?	?	?	?	X	√	X	−0.15-10% of rate	No R_D limit	-400-800 (-224-427)	≤5,700 (39,900)
Thermal Probe	<72 (1800)	X	√	?	√	√	√	?	√	√	?	?	?	?	X	?	?	X	X	?	X	−1-2% URV	No R_D limit	1,500 (816)	Pipe rating
Solids Flowmeter	<24 (600)	X	X	X	X	X	X	SD	X	?	X	X	SD	SD	X	SD	SD	X	√	X	X	−0.5% of rate to ffl4% URV	-	750 (400)	≤580 (4,000)
Correlation																									
Capacitance	<8 (200)	X	X	X	X	X	X	√	√	√	√	√	√	√	X	?	?	X	?	?	X	No data available	No data available	300 (149)	≤580 (4,000)
Ultrasonic	>0.5 (12)	X	X	X	X	X	X	?	√	√	√	√	√	√	X	?	X	X	X	?	X	−6% of ??	No data available	-300-250 (-180-120)	Pipe rating

cP = centi Poise
cS = centi Stokes
SD = Some designs
? = Normally applicable (worth consideration)
√ = Designed for this application (generally suitable)
URV = Upper Range Value
X = Not applicable
‡ According to other sources, the minimum Reynolds number should be much higher
* Liquid must be electrically conductive
** Range 10:1 for laminar, and 15:1 for target
*** Newer designs linearize the signal

Table (2) Flow meter Characteristics Comparison Sheet[52]

METER TYPE	Accuracy of sensor[1]		Rangeability (Range for stated accuracy)	Reynolds number (Minimum)	Piping required (Diameter, inches)	Pressure limit (psig)	Temp. limit (°F)	Notes [(1)] System accuracy depends on system design, quality of maintenance, etc.
	Proved	Unproved						
HEAD METERS (Flow proportional to $[\Delta P]^{0.5}$)								
Orifice	0.25	1.50	3:1	4,000	See Ch. 11	ML	ML	Square-edged, concentric
Flow nozzle	0.50	1.50	3:1	10,000	10-40	ML	ML	ASME
Venturi	0.50	1.50	3:1	7,500	5-30	ML	ML	
Elbows	0.50	3.00	3:1	10,000	10-40	ML	ML	Prepared as a meter
LINEAR METERS (Flow proportional to flow velocity)								
Non-Intrusive ("Open-pipe" bore)								
Coriolis	0.25	1.00	5:1 to 25:1	3,000	None	ML	ML	
Ultrasonic								
Doppler	2.00	5.00	10:1		10	To ANSI 2500		
Transit time	0.50	1.00	10:1 (1)		10	To ANSI 2500	-4 to 185	
Intrusive (Sensing element intrudes into bore)								
Multiphase	5-10	5-10			None			
Positive displcm't	0.25	1.00	20-1		None			
Turbine, liquid	0.10	0.50	10-1	No limit	10	1400	150	
Vortex shedding	0.5	2.00	10:1 to 30:1	10,000	5-40	2500	400	

(1) Extended low-flow meters rangeability to 50:1 ML = Material limit

Table (2-a) Flow meter Characteristics Comparison Sheet[52]

METER TYPE	Accuracy of sensor [1]		Rangeability (Range for stated accuracy)	Reynolds number (Minimum)	API upstream piping (X-Diam.)	Pressure limit (psig)	Temp. limit (°F)	Notes [(1)] System accuracy depends on system design, quality of maintenance, etc.
	Proved (±)	Unproved (±)						
HEAD METERS (Flow proportional to $[\Delta P]^{0.5}$)								
Orifice	0.25	1.50	3:1	4,000	See Ch. 11	ML	ML	Square-edged, concentric
Flow Nozzle	0.50	1.50	3:1	10,000	10-40	ML	ML	ASME
Venturi	0.50	1.50	3:1	7,500	5-30	ML	ML	
Elbows	0.50	3.00	3:1	10,000	10-40	ML	ML	Prepared as a meter
LINEAR METERS (Flow proportional to flow velocity)								
Non-intrusive ("Open-pipe" bore)								
Coriolis	0.5	1.50	5:1 to 25:1	3,000	None	ML	ML	
Ultrasonic								
Doppler	2.00	5.00	10:1	5,000	10	To ANSI 2500	-300 to 200	
Transit Time	0.50	1.00	10:1 (1)	3,000	10	To ANSI 2500	-300 to 200	
Intrusive (Sensing element intrudes into bore)								
Multiphase	5-10	5-10						
Turbine, gas	0.25	0.3	10:1 to 140:1	4,000	10	1,400	150	
Vortex shedding	0.5	2.00	10:1 to 50:1	4,000	5-40	2,500	400	

(1) Extended low-flow meters rangeability to 50:1 ML = Material limit

CHECK POINTS FOR FLOWMETER SELECTION

Ask the following questions when selection a flowmeter for your application

1. What range do you want to cover?	(0~100%),(25~100%) ,(50~100%), Other
2. What accuracy do you need? At	100%, 75%, 50%, 25%
3. What do you intend to do with meter put?	Indicate, Totalize, Record, Transmit, Other
4. What type of enclosure do you want?	Wall mount, Panel mount, NMEA Code
5. What are your piping considerations?	New, Existing, Elevation, Straight Pipe Run, Accessibility, Environment
6. Who will service the meter?	Troubleshoot, Calibrate
7. What type of service live do you want from the meter?	**NA**
8. What pressure drop can you accept through the meter?	**NA**
9. How much money can you appropriate?	**NA**
10. What do you want to meter?	Steam, Condensate, Natural Gas, Fuel Oil(Grade), Chilled Water, Heating Hot Water, Tower Water, Domestic Water, Other
11. Other Data Required:	Pressure (min, max, normal) Temperature (min, max, normal) Viscosity (min, max, normal) Flow Rate (min, max, normal) Pipe Size (ID)

NA: NOT AVAILABLE.

Assessment of measurement methods used in production

Standards of Accuracy—Summary

Injection Systems

		Maximum uncertainty of monthly volume	Single point measurement uncertainty
(i)	Total gas	5%	N/A
(ii)	Well gas	N/A	3%
(iii)	Total water	5%	N/A
(iv)	Well water	N/A	5%

Oil Systems

		Maximum uncertainty of monthly volume	Single point measurement uncertainty
(i)	Total battery oil (delivery point measurement)		
	Delivery point measures > 100 m^3/d	N/A	0.5%
	Delivery point measures ≤ 100 m^3/d	N/A	1%
(ii)	Total battery gas (includes produced gas that is vented, flared, or used as fuel)		
	> 16.9 10^3 m^3/d	5%	3%
	> 0.50 10^3 m^3/d but ≤ 16.9 10^3 m^3/d	10%	3%
	≤ 0.50 10^3 m^3/d	20%	10%
(iii)	Total battery water		
	> 50 m^3/month	5%	N/A
	≤ 50 m^3/month	20%	N/A
(iv)	Well oil (proration battery)		
	Class 1 (high), > 30 m^3/d	5%	2%
	Class 2 (medium), > 6 m^3/d but ≤ 30 m^3/d	10%	2%
	Class 3 (low), > 2 m^3/d but ≤ 6 m^3/d	20%	2%
	Class 4 (stripper), ≤ 2 m^3/d	40%	2%
(v)	Well gas (proration battery)		
	> 16.9 10^3 m^3/d	5%	3%
	> 0.50 10^3 m^3/d but ≤ 16.9 10^3 m^3/d	10%	3%
	≤ 0.50 10^3 m^3/d	20%	10%
(vi)	Well water	N/A	10%

Gas Systems

		Maximum uncertainty of monthly volume	Single point measurement uncertainty
(i)	Gas deliveries (sales gas)	N/A	2%
(ii)	Hydrocarbon liquid deliveries		
	Delivery point measures > 100 m^3/d	N/A	0.5%
	Delivery point measures ≤ 100 m^3/d	N/A	1%
(iii)	Plant inlet or total battery/group gas	5%	3%
(iv)	Plant inlet or total battery/group condensate (recombined)	N/A	2%
(v)	Fuel gas		
	> 0.50 10^3 m^3/d	5%	3%
	≤ 0.50 10^3 m^3/d	20%	10%
(vi)	Flare gas	20%	5%
(vii)	Acid gas	N/A	10%
(viii)	Dilution gas	5%	3%
(ix)	Well gas (well site separation)		
	> 16.9 10^3 m^3/d	5%	3%
	≤ 16.9 10^3 m^3/d	10%	3%
(x)	Well gas (proration battery)	15%	3%
(xi)	Well condensate (recombined)	N/A	2%
(xii)	Total battery water	5%	N/A
(xiii)	Well water	N/A	10%